Long Term Development Statement

SP Manweb

For the years 2024/25 to 2028/29
November 2024

Welcome to our

Long Term Development Statement

Welcome to our Long Term Development Statement (LTDS). This publication provides detailed network planning data to enable users to evaluate opportunities associated with our networks. Sharing such data and working with our customers and stakeholders are critical to delivering a successful and just transition to Net Zero.

Electricity networks are at the heart of the Net Zero transition. Our main role is to provide the safe, efficient, and reliable network capacity needed to enable the decarbonisation route that our customers and communities choose.

We know from detailed modelling that this new demand, generation, and storage will increasingly push the distribution network beyond what it is designed for, meaning that our network needs to evolve to enable our customers' Net Zero transition.

Annually publishing our LTDS is just one measure we take to increase the transparency of how we plan and operate our distribution network, and is aligned with our approach of sharing an increasing range of network data with stakeholders.

The energy system requires significant digitalisation to meet the needs of current and future energy consumers, users and stakeholders. As the industry progresses towards more data-driven and interoperable systems, reforming the LTDS is essential to enhance its accessibility, accuracy and alignment with industry standards.

We are working closely with our regulator, Ofgem, and industry stakeholders to reform the LTDS. The revised form of LTDS will be introduced in 2025 and will provide grid model data using Common Information Model (CIM) data standard. This will significantly improve interoperability across the industry and greatly support users to access network data.

We hope you enjoy reading the LTDS. This document presents the 2024 LTDS network data annexes, supplemented by datasets that are accessible via our Open Data Portal.

If you have any queries on the LTDS publication or data, you can contact us via the means included in Section 1.9 Contact Information.

Contents

The information used to compile this Statement is derived from SP Manweb plc's own data. Whilst all reasonable care has been taken in the preparation of this data, SP Manweb plc is not responsible for any loss that may be attributed to the use of this information.

The Distribution Long Term Development Statement has been prepared by SP Manweb plc in accordance with Condition 25 of the Electricity Distribution Licence, issued under the Electricity Act 1989. The Statement is prepared in a form specified by the Gas and Electricity Markets Authority.

Registered Office: 3 Prenton Way, Prenton, CH43 3ET

1. Part 1: Introduction

1.1. Who We Are

We are SP Energy Networks, part of the ScottishPower Group of companies. We own and operate three electricity network licences:

- SP Transmission plc (SPT) is responsible for the transmission network in central and southern Scotland.
- SP Distribution plc (SPD) is responsible for the distribution network in central and southern Scotland.
- SP Manweb plc (SPM) is responsible for the distribution network in Merseyside, Cheshire, North Wales, and North Shropshire.

It is through these networks of underground cables, overhead lines, and substations that we provide, on behalf of supply companies, 3.5 million homes, businesses, and public services with a safe, reliable, and efficient supply of electricity.

1.2. Purpose of the SP Manweb Long Term Development Statement

The Long Term Development Statement (LTDS) provides information on the operation and development of our 132kV, 33kV and 11kV distribution network in our SP Manweb licence area. This includes a range of information such as network asset technical data, network configuration, geographic plans, fault level information, demand and generation levels, and planned works. This information is contained in attached Excel and pdf files which, together with this summary document, form the LTDS.

The purpose of the LTDS is to provide information on the distribution system that may be of use to developers wishing to connect to, or make use of, the distribution system. Information on how to connect onto our network can be found on our website[1].

The data is provided to enable developers to identify opportunities and carry out high level assessments of the capability of the network to support their demand or generation development. Future network development plans are included to advise existing and potential users of significant changes to the system, which may have an impact on their development plans.

A main update is published every November with a minor update every May.

[1] Available here: www.spenergynetworks.co.uk/pages/getting_connected.asp

1.3. How the LTDS Fits with Other Data Provision

Publishing our LTDS is just one measure we're taking to increase the transparency of how we plan and operate our distribution network, and is aligned with our approach of sharing an increasing range of network data with stakeholders. Other ongoing data provision includes:

- Distribution Future Energy Scenarios (DFES)[2] – these are forecasts for key customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK & devolved government targets and other industry forecasts. Given the uncertainties out to 2050, we create forecasts for four main energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback. We update our DFES annually.
- Network Development Plan (NDP)[3] – the primary objective of the NDP is to provide information on available network capacity to accommodate demand and generation growth, and interventions the DNO plans which will increase network capacity (such as flexibility use and reinforcement). The NDP is a medium-term outlook and is designed to sit between shorter-term LTDS and long-term DFES.
- Embedded Capacity Register (ECR)[4] – previously known as the System Wide Resource Register, this provides information on generation and storage resources (≥50kW) that are connected, or accepted to connect, to our distribution network. It is updated on the 10th working day of each month.
- Heatmaps[5] – this interactive mapping tools provides a geographic view of where there is available network capacity to accommodate new generation.
- Flexibility tenders – we tender for flexibility for all viable network constraints. When we run tenders we publish information on the location, magnitude, and duration of the constraint. In some cases, we will also send ceiling price information. We run tenders twice annually.

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[2] Our DFES is available here:
https://www.spenergynetworks.co.uk/pages/distribution_future_energy_scenarios.aspx
[3] Our NDP is available here:
https://www.spenergynetworks.co.uk/pages/network_development_plan.aspx
[4] Our ECR is vailable here:
https://www.spenergynetworks.co.uk/pages/embedded_capacity_register.aspx
[5] Our heatmaps are available here:
https://www.spenergynetworks.co.uk/pages/connection_opportunities.aspx

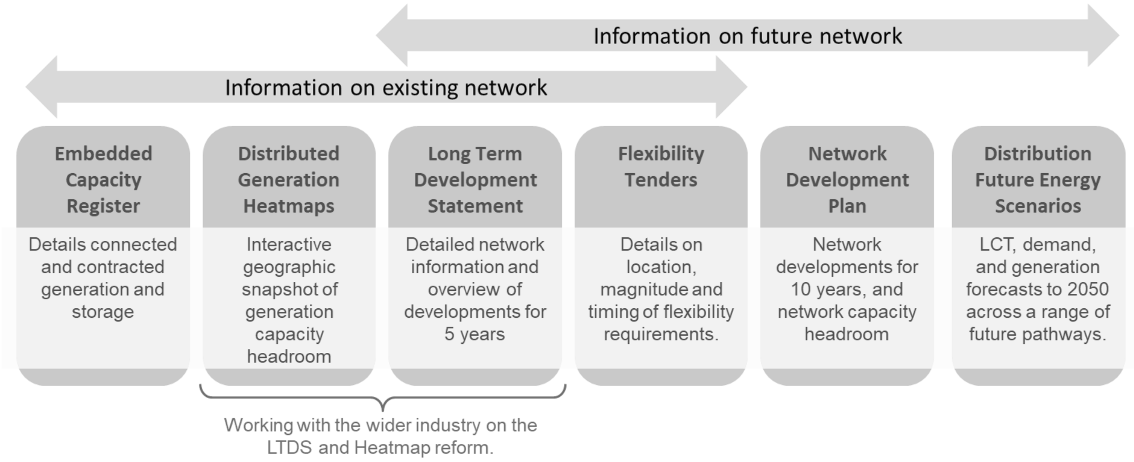

Figure 1: How our LTDS fits with other data provision

Looking forward, given the value of data share, we plan to share a wider range of historical, near-time, real-time, and forecast data with stakeholders. This will be underpinned by infrastructure to gather, assess, and share data, and engagement with stakeholders to prioritise data publication. Please see our Open Data Portal[6] for more information on the network data we share and our Data Strategy.

Common Information Model (CIM)

As the industry progresses towards more data-driven and interoperable systems, reforming the LTDS is essential to enhance its accessibility, accuracy, and alignment with industry standards. The revised form of LTDS introduces important new requirements for providing grid model data using CIM data standard, improving interoperability across the industry and to maximising opportunities for users to access network data. This initiative aims to modernise and enhance the management and presentation of our data.

The LTDS reforms commenced in August 2021, following extensive consultations with industry stakeholders and regulatory bodies. The project is structured in phases, with each phase focusing on specific aspects of the reformation to ensure smooth transition and implementation. The CIM Physical grid model (EQ profile only) representing the existing grid of the entire licence area, will be published in November 2025. We are working closely with our regulator Ofgem and the industry to identify ongoing improvements and reforms to LTDS.

We will ensure our publications are aligned with the latest developments and requirements from this national working group. Further details can be found on the Ofgem website[7].

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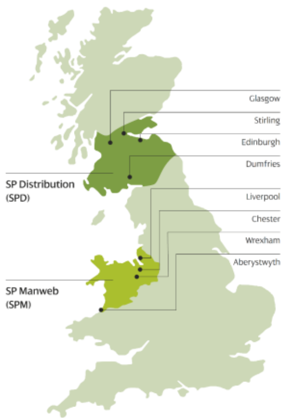
[6] Our Open Data Portal. Available at: https://spenergynetworks.opendatasoft.com/pages/home/

[7] Long Term Development Statement direction. Available at: https://www.ofgem.gov.uk/decision/long-term-development-statement-direction

1.4. An Introduction to the SP Manweb Network

The SP Manweb distribution network supplies nearly 1.53 million customers in Merseyside, Cheshire, North Wales and North Shropshire and covers an area of over 12,329 km^2. Electricity from local distribution-connected generation and National Grid's 400kV and 275kV transmission network is distributed to our customers though a succession of networks operating at 132kV, 33kV, 11kV, 6.6kV, 6.3kV and 400/230V. There are also connections to adjacent distribution networks – Electricity North West to the northeast, National Grid Electricity Distribution (West Midlands) to the east, and National Grid Electricity Distribution (South Wales) to the south.



SP Manweb Network Overview

Distribution voltages:

132kV, 33kV, 11kV, 6.6kV, 6.3kV and 400/230V

Assets (HV and above):	
Overhead lines:	15,398 km
Underground cables:	10,119 km
Transformers:	46,410
Customers:	1.53 million
System Max Demand:	2.64 GW
Connected Generation:	2.84 GW
Contracted Generation:	4.71 GW

Our SP Manweb network is unusual in GB as the majority is an interconnected or “meshed” design. This means power can flow through multiple routes to the point of use. By comparison, most GB distribution networks have a traditional radial design, where power typically has only one possible path. The interconnection extends across our entire 132kV and 33kV network and over half our HV and LV network.

This interconnected design was inherited to us when the electricity supply industry was privatised. Its primary advantage is that it gives our customers a highly reliable electricity supply – our urban customers have on average the most reliable supply in GB. An outage due to a HV network fault in our urban areas is experienced only once every 20 years, and customers do not lose supplies in over 95% of 33kV network faults. Other benefits of this design are that it is inherently adaptable and scalable, and it can accommodate low carbon technology (LCT) growth well. These advantages are becoming increasingly valuable to our customers as they decarbonise to Net Zero and become more dependent on a reliable supply.

However, once interconnected capacity is saturated, reinforcement of the network is more expensive than for radial networks. This is because new sites must be established and because interconnected networks have more assets per customer to replace. Some of these assets are exclusive to our SP Manweb unique network, and some are more expensive than those on a comparable radial network. As a result, it costs more to operate, maintain, and modernise compared to all other DNOs.

Customer demand on the distribution system and the operation of generators are dynamic in nature and are dependent on many factors. The weather, dawn/dusk times, social or sports events, and relative fuel cost all play a part in shaping the load profile and generation patterns. The demand on the SP Manweb distribution system varies throughout the day and over the seasons. Peak demand on the system generally occurs on a weekday in mid-winter and the minimum demand at the weekend during summer. The maximum system demand for the SP Manweb area for 2023/2024 was 2,639MW on 18 January 2024 for the half hour period ending 18:30 hours.

Looking forward, our DFES forecasts a considerable increase in the medium to longer term driven by the electrification of customer heat and transport and increases in industrial and commercial load. We are also going to see a further leap in embedded renewable generation to power these. We will need to use a range of intervention types to accommodate this growth, included flexibility services, smart solutions, energy efficiency, network reinforcement, and new innovative solutions.

1.5. Content of the Long Term Development Statement

The Long Term Development Statement consists of the following content:

Part 1: Introduction

Part 2: Summary Information

- Network long term vision
- Design and operation philosophies of the network
- Network characteristics
- Indication of geographical arrangement of the network
- Statutory obligations and industry standards
- References to engineering recommendations and SPEN documentation
- Contact information

Part 3: Detailed Information

- Schematic diagrams detailing the normal operation of the distribution network
- Table 1: Circuit Data
- Table 2: Transformer Data
- Table 3: System Loads
- Table 4: Fault Levels
- Table 5: Embedded Generation
- Table 6: Connection Activity
- Table 7: Substation Abbreviation Codes
- Table 8: Predicted Changes
- Table 9: System Schematics
- Table 10: Geographic Plans

Part 4: Development Proposals

- Network development proposals
- Connection request statistics

The information contained within this document is derived from SP Manweb plc's own data. Whilst all reasonable care has been taken in the preparation and consolidation of this data, SP Manweb is not responsible for any loss that may be attributed to the use of this information.

1.6. Annual Publication and Obtaining the LTDS

The network changes over time and the data contained within the LTDS include the known and anticipated developments at the data freeze date, usually the end of August each year. The analytical models, which form the basis of the LTDS data, are finalised by the end of October. System maximum demand data and Bulk Supply Point (BSP) loads are for the period April to March. The detailed data tables section (Part 3: Detailed Information) is fully reassessed on an annual basis for publication in November each year. A brief mid-year update summary is published in May.

Access to the LTDS requires registration. After registration, the LTDS document and associated data tables are available for download. There is no cost either for the registration or the download – accessing the LTDS is free of charge.

1.7. Engaging with Stakeholders

Stakeholder views are important to us. We have been engaging with stakeholders and customers to understand our stakeholder's priorities. This covered a wide variety of areas, from storm resilience and flood protection, to improving supplies to poorly served customers, future proofing the network and innovation to provide network capacity information for new customers.

In response to requests, over recent years we have sought to improve the content and data format of the LTDS, it is now more widely accessible with data provided in more convenient formats.

Information on the location of network assets and capacity available can be found using our interactive mapping tool.

We continue to work with Ofgem and welcome stakeholder and customer feedback; please visit our website for further details[8].

1.8. Further Regulatory Information

SP Energy Networks is a regulated business. We must meet certain criteria in order to meet our licence conditions. You can find further details on our website[9].

[8] Available here: https://www.spenergynetworks.co.uk/pages/stakeholder_engagement.aspx
[9] Available here: https://www.spenergynetworks.co.uk/pages/regulation_guidance_leaflets.aspx

1.9. Contact Information

Should you wish clarification on any aspect of this document, please contact:

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Glasgow G2 5AD

Email: ytan@spenergynetworks.co.uk

Please see Section 5.4 for contact details for other parts of SP Manweb and SP Energy Networks (such as new connections) and for other organisations mentioned in our LTDS.

Opportunities exist for the connection of new load or generation throughout our distribution system. System conditions and connection parameters are site specific and therefore the economics of a development may vary across the system. Developers are encouraged to discuss their development opportunities and we will be pleased to advise on connection issues.

2. Part 2: Summary Information

2.1. Context

All numbers in this Section 2.1 are for SP Energy Networks (i.e. totals for SP Distribution and SP Manweb) unless stated otherwise.

2.1.1. Our Evolving Role

Our customers prioritise four main things in their electricity supply: reliability, safety, cost-efficiency, and the freedom to consume when they want (domestic customers especially do not want to be compulsorily constrained). The challenge for us is how to continue delivering these customer priorities against a radically changing energy landscape, not least significant demand and generation growth as customers decarbonise.

Common to meeting these different priorities is the need to efficiently provide the capacity our customers need in the timescales they need it. We will do this to accommodate customer demand and generation growth, deliver a Just Transition to Net Zero, and ensure the continued safe, reliable, and efficient operation of the distribution network and wider system.

A changing energy landscape

Our distribution network was largely developed in the 1960s' to deliver electricity from big transmission-connected fossil fuel power stations to our customers. The network was configured into four main voltage levels for this, and was sized to accommodate industrial, commercial, and typical domestic demand. Initially, just one in ten homes were electrically heated, and there were no EVs.

This model has incrementally evolved over many years to meet changing customer needs. We have rolled out monitoring and control across the higher voltage networks, although the LV network remains largely unmonitored. We have materially improved network reliability through better asset management. And we have delivered new technologies, such as active network management, to offer quicker and lower cost connections and accommodate renewable generation growth.

In short, the story of the last 60 years is one of customers' needs evolving steadily and incrementally. Our existing network capacity, planning tools, operational systems, and internal processes are tailored to these customer needs.

This slow evolution is now over. The energy landscape is changing fast as the way our customers generate, use, and interact with energy evolves. Three key trends are driving this:

- Decarbonisation – in response to the climate emergency, we need to achieve Net Zero greenhouse gas emissions by 2045 in Scotland and 2050 in England and Wales. To deliver this decarbonisation, we need to electrify a significant proportion of transport and building heating. We also need to complete the transition of our generation mix from fossil fuel to zero carbon generation by 2035[10]. These changes will significantly increase the levels of demand and generation that we need to connect to the distribution network for our customers.

- Decentralisation – the volume of generation which is smaller-scale and connected to the distribution network rather than the transmission network is increasing. This decentralisation has two effects: we must find ways to accommodate more customer generation than the distribution network is currently designed for; and as traditional transmission-connected generators close, the national energy system operator (NESO), fomer ESO, has an increasing reliance on this DG and other controllable customer assets connected to the distribution network (collectively known as distribution energy resources, DER) to maintain GB system stability.
- Democratisation & digitalisation – means the rise of the active domestic customers (aka prosumer). Smart meters, home energy management systems, intelligent domestic and electric vehicle (EV) storage, specialist aggregators and suppliers – these are all reducing the barriers for domestic customer participation in the energy system. Democratisation has two effects: domestic customer consumption profiles are becoming less predictable and more dynamic; and we can increasingly work with many individual customers and communities, rather than just large DG or industrial customers, to source vital network and system services.

Forecasting and modelling the changes

To better quantify these drivers and ensure we meet our customers' changing electricity needs, we forecast what their electricity requirements are going to be into the future. We do this by developing DFES forecasts[11], and then comparing these against Net Zero compliant scenarios from the NESO[12] and the Climate Change Committee (CCC)[13] to identify the range of Net Zero compliant investment scenarios.

All Net Zero compliant scenarios show a significant increase in the volume of customer demand and generation that we will need to serve on our distribution network. This is primarily due to the electrification of transport (more EVs), the electrification of heat (more heat pumps), and more renewable generation (DG). Table 1 shows these values for the low, baseline, and high investment scenarios for our RIIO-ED2 Business Plan (2023/24 to 2027/28)..

[10] https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035
[11] Our "Distribution Future Energy Scenarios", republished with our RIIO-ED2 final submission Business Plan, are included as RIIO-ED2 Business Plan Annex 4A.6. Available at: https://www.spenergynetworks.co.uk/pages/distribution_future_energy_scenarios.aspx
[12] The National Energy System Operator's "Future Energy Scenarios", available at: https://www.neso.energy/publications/future-energy-scenarios-fes/fes-documents
[13] The Climate Change Committee's "Sixth Carbon Budget", published December 2020. Available at: https://www.theccc.org.uk/publication/sixth-carbon-budget/

Table 1: Our RIIO-ED2 low, baseline and high scenario

Investment Scenario	Total SP Energy Networks uptake by 2028		
	EVs	Heat pumps	Additional DG
High scenario	1.03m	0.81m	+6.37GW
Baseline scenario	0.67m	0.37m	+4.95GW
Low scenario	0.65m	0.34m	+4.95GW

The magnitude of these changes is significant and unprecedented – customer needs have never changed at this scale or rate before.

We model the impact of these scenarios on our network using enhanced forecasting and modelling tools. We combine our investment scenarios, enhanced forecasting tools which predict EV and heat pump uptake for every customer we serve, our Engineering Net Zero (ENZ) Model (a full network analytical model including all 48,000km of LV), flexibility tenders for every single forecast constraint (1,557 sites), and an optimisation engine which impartially analyses and sequences all viable technical and non-technical solutions (including flexibility and energy efficiency) to create bespoke intervention plans for every constraint.

This approach systematically identifies where, when, and how we need to intervene. We're not building a plan on statistical estimates – we're addressing individual known constraints using market tested solutions. This data-driven approach means we build efficient targeted intervention plans – this keeps costs efficient for our customers and ensures they get the capacity they need to decarbonise. This is a step change in how investment plans are developed, which sets the standard for others to follow.

Responding to the challenge

Our forecasting and modelling showed that customer-led changes out to 2050 are far beyond what the network, our operational systems, and our internal processes are designed for. This creates four core areas we must deliver:

Create additional network **capacity**	Manage increasing **complexity**	Respond to increasing network **criticality**	Manage deteriorating asset **condition**
so we can accommodate our customers' EVs, heat pumps, and generation.	to safeguard the distribution network and whole system, and to enable new markets and services to operate safely and efficiently.	as our customers become increasingly dependent on their electricity supply for all their activities.	as utilisation and criticality increase due to greater levels of demand and generation.

We will respond by delivering:

- **Capacity**, through a combination of flexibility services, smart solutions, and network reinforcement. We will tender for flexibility services for all viable constraints.
- **DSO capabilities**, to expand our toolbox of solutions to support flexibility markets, analyse and share data, enable transparency and competition, and help manage a more complex and interactive system (see below).
- **Asset management interventions**, to manage the risk, reliability, resilience, and safety of our network. We will reduce the frequency of customer power cuts by 19% and their duration by 19%, and protect our customers served by rising and lateral mains.
- **Environmental interventions,** to reduce the environmental impact of our network and to increase its resilience to climate change.
- **Continued innovation,** to help deliver a safer, more reliable, and more cost-efficient Net Zero system (see below).

DSO

Simply providing more capacity by itself is not sufficient to address the complex range of challenges we face. We also need to adapt to more dynamic and volatile power flows, more energy system participants, greater interactivity across the whole energy system, and the need for greater coordination with the NESO.

We have developed a comprehensive DSO Strategy in response. In RIIO-ED2, this includes new infrastructure, such as an integrated simulation and modelling platform for our entire network (including all 48,000km of LV) so that we can make real-time data-driven planning and operation decisions, and LV monitoring at 14,102 secondary substations to increase network visibility and extend coverage from 14% to 76% of customers. It also includes new DSO outputs, such as sharing outage information with gas companies and providing near-time dispatch and "no need" notifications to flexibility providers to increase whole system efficiency.

Our strategy will give us more network visibility, greater data analysis and sharing capabilities, enhanced forecasting and analytical tools, improved planning and operational coordination (not just with the NESO but also other network companies and vectors), new infrastructure to manage an increasingly complex array of network interventions, and greater use of flexibility (supported by increased data sharing, digital platforms, and transparency). It gives us the tools and capabilities we need to enable the customer-led revolution of the energy system.

Delivering DSO involves big changes for us. We will have to deliver a new system architecture, new ways of working, and new interactions with customers and stakeholders. Given the extent of these changes, and the importance to Net Zero, system stability, and our customers of getting it right, it is essential that our organisation is correctly structured to deliver DSO. For this reason, we have prepared a new DSO functional business model. It will be responsible and accountable for delivering DSO, whilst providing enhanced transparency to our stakeholders on our approach to designing and operating the network that we need.

We are best placed to lead the delivery of DSO. We have the capability, knowledge, and experience to deliver on time and in a cost-effective way. We have strong links with our customers and communities, which means we can quickly understand and respond to their needs. Most importantly, retaining a link between DNO and DSO means there is clear responsibility for the safety of network assets that enter into our customers' homes. We have our customers' interests at the heart of our decisions, as we seek to deliver an essential service that is safe, reliable, and resilient.

2.1.2. Network Operation and Innovation

It is clear that change is necessary to ensure a cleaner and more sustainable energy future and safely operate the more complex, dynamic, and interactive energy system. We are developing and delivering new innovative technologies that accommodates these changes, improves the way our network operates, and brings benefits to our customers. We have carried out extensive work to understand the impact of new forms of electricity generation and changes to the electricity usage on our networks. We are working with our stakeholders to understand what will happen as more people move towards LCTs. A sample of our innovation projects include:

Network forecasting

We have delivered a suite of innovation projects covering forecasting (EV-Up, Heat-Up, and Charge) and modelling (NCEWS and Network Analysis and View, NAVI). These projects help us better predict customer LCT uptake, and more accurately assess their network impact.

This means we can better target the right interventions at the right time. This results in more efficient expenditure, facilitates the use of flexibility services, and reduces delays for customers waiting for capacity. Consequently, we used these tools to develop our RIIO-ED2 Business Plan and will continue to use them throughout RIIO-ED2.

Fault level monitoring and active management

We partnered with Outram Research Ltd to develop the world's first real-time fault level monitor. For the first time for any DNO, this gives an accurate real-time understanding of network fault level. We combined this innovation with a network management scheme – another first. These innovations allow us to safely connect more generation without triggering fault level reinforcements.

This is good for our generation customers, who can connect quicker and at lower cost. It is also beneficial for our wider customer base, who pay a portion of interventions to manage fault level. Due to these advantages, we have included this system in our plans to manage 41 sites with higher fault levels and to facilitate lower cost generation connections. Deployment of these sites is in progress and on track for completion by the end of RIIO-ED2..

Flexibility services

In July 2024, we introduced a new month ahead operating model following stakeholder feedback that shorter-term regular tenders are preferable for some providers that intend on participating in the DNO flexibility markets. The month ahead model ensures convenience and increased opportunity to tender when appropriate for new as well as existing providers. Additionally, nearer to real-time month ahead tenders reduces elements of market barriers to entry, as providers are able to offer robust bid prices that reflect current market prices. This reduces the forecasting risk of expected market prices in longer term flexibility competitions.

Moreover, we were among the first to use flexibility services to provide additional network security during planned maintenance providing supply security for our customers during outages and creating further opportunities for Flexibility Services Providers. Throughout 2024 we have contracted flexibility with Statkraft to support the reinforcement of the network between Aberystwyth and Barmouth. Rheidol Power Station will be ready to respond in the event of a fault during these planned reinforcement works as the network will be more reliant on a single 132kV overhead line circuit. Through this partnership we are able to restore power in the event of an outage, potentially within 30 minutes. Flexibility therefore allows for more capacity and support with planned works, it makes our network more resilient and can reduce disruption for customers.

As part of our Just Transition strategy we are seeking to ensure that all of our customers are able to participate and benefit from providing network flexibility. We recently launched our Equiflex project, as part of an Strategic Innovation Fund (SIF) we are working with key partners such as East Ayrshire Council, Energy Action Scotland and Frazer Nash to understand how fuel poor customers can benefit and take part in network flexibility. This project was recently approved by Ofgem to progress to the SIF Alpha phase.

The Equinox Trial is a DNO heat pump trial driven by multiple project partners including NGED, Octopus, Scottish Power's customer business and Guide House. The Equinox Trial is exploring methods of introducing flexibility to heat pump usage to delay network reinforcement. The first trial (December 2022 - March 2023) demonstrated that households could significantly reduce heating demand when required. The second trial focused on expanding demographic participation, including vulnerable customers, and the third trial which will take place in November 2024 to January 2025 will test scalability across different DNO networks, with SPEN facilitating this expansion to assess the method effectiveness in both our licence areas.

Active Network Management and Constraint Management Zones

Active Network Management (ANM) is a key technology that DNOs use to connect increasing levels of distributed generation to networks which were previously considered to be at or approaching full capacity. These generators are connecting in accelerated timescales and for a fraction of the cost of reinforcement solutions.

We have deployed wide scale active network management across the Dumfries and Galloway network area in our SP Distribution network. This regulates the output of DG to avoid transmission constraints – this type of coordination across transmission and distribution is a UK first. The scale and nature of this project (one of the largest of its type) provides invaluable learning for further developing constraint management zones in RIIO-ED2 and extending their functionality to coordinate a wide variety of DSO functions.

In RIIO-ED2 we will deploy a new network control architecture – called Constraint Management Zones (CMZs) in 22 areas of the network. These will be at the heart of network operation in RIIO-ED2 and a key part of our DSO infrastructure. Please see our DSO Strategy for more information[14].

[14] Available here: https://www.spenergynetworks.co.uk/userfiles/file/SPEN_ED2_DSO_Strategy_Report_July_2021.pdf

Establishing technical limits

As part of the Energy Networks Association's (ENA) Strategic Connections Group (SCG), we have been working collaboratively with NESO, Transmission Owners (TOs) and other DNOs to establish Technical Limits on the transmission and distribution boundary. This allows DNOs to manage the flows at the interface points between the agreed limits and provide customers with a flexible connection on a temporary basis, ahead of transmission reinforcement works being completed. These accelerated connections will need to be managed through ANM and will be subject to uncompensated curtailment.

As part of Phase 1A we have agreed Technical Limits at 4 of our GSPs in the SP Manweb network, with offers issued to eligible customers enabling accelerated connection timescales. The accelerated connections timescales are subject to our Constraint Management Zones (CMZ) rollout plan for establishing ANM which will enable us to be manage the generation connections within Technical Limits.

We are currently working to further roll out Technical Limits at the remaining GSPs in our SP Manweb network. We will be issuing an Expression of Interest (EOI) to the eligible customers

Within the SP Distribution network we have been employing Load Management Schemes (LMS) as a way of connecting customers to the distribution network earlier and ahead of transmission reinforcement works. LMS is a system comprised of geographically distributed measuring devices and site-specific customer interfaces to detect, in real-time, unacceptable overloading of transmission assets to disconnect the generation contributing to the overload in accordance with contractual agreements.

Battery storage solutions

As part of the Energy Networks Association's (ENA) Strategic Connections Group (SCG), we led the Battery Storage Connections (BSC) subgroup, aimed at alleviating the challenges created by an unprecedented number of battery storage projects seeking to connect to the GB distribution network. The subgroup successfully developed, published and implemented three tactical solutions, which have also been endorsed by our regulator Ofgem.

The first two tactical solutions release underutilised contracted capacity and help DNOs to only build new capacity if needed. The first tactical solution involves a common interpretation of network access rights for new battery storage connections where both their import and export can be curtailed in abnormal network condition. The second tactical solution provides a standard approach when assessing security of supply of the distribution network. This applies to existing and contracted connections, providing guidance on how to treat battery storage when calculating network capacity.

The third tactical solution encourages DNOs to incorporate up to 10 years of LCT forecast growth when accessing new battery storage connections. This safeguards network capacity for near-term societal decarbonisation.

In addition to the three tactical solutions, we will continue leading the BSC subgroup to consider medium-to-long term solutions.

2.2. The Power Supply System

The Electricity Act 1989, as amended by the Utilities Act 2000, requires the holder of an Electricity Distribution Licence to develop and maintain an efficient, co-ordinated, and economical system of electricity distribution. The licensee is also required to facilitate competition in the generation and supply of electricity.

This LTDS provides for those interested in the development opportunities offered within the SP Manweb area, an overview of the factors that are relevant to the future development of the power system.

This section provides an overview and basic information on the technical aspects of distribution power system operation and planning.

2.2.1. Electricity System Operation and Balancing

The power supply system is planned and operated to provide secure and economic supplies of electricity to customers. Security and quality of supply is achieved through controlling and maintaining system voltage and frequency to within a satisfactory bandwidth around their nominal operating values.

Frequency

The frequency of the power system is determined by the balance of generation and demand at any one time. In the UK, the power system nominal frequency is 50 Hz. If generation exceeds demand, the system frequency will increase above nominal and if demand exceeds generation, the frequency will decrease below nominal. In general, system frequency continuously varies within the operational limits of 50.2 - 49.8 Hz, depending on the degree of mismatch between generator output and system demand. It is controlled by the NESO to within this operating range by means of manual and automatic interventions as required.

For contingency conditions, reserve generation must be available to cover the largest credible loss of generation or sudden increase in system demand.

Voltage

The voltage at any point on a power system is determined through a combination of:

- the voltage of generating plant connected in the surrounding area;
- the nature and parameters of the network through which the power is transferred;
- the level of power flow; and
- the electrical characteristics of customers demand in the area.

The voltage of the primary transmission system is controlled by varying the voltage ratio (tap changing) of generator transformers. This alters the excitation of generators, up to the limits of their operating characteristics. Voltage control at the interface between transmission and distribution systems is usually carried out by automatic on-load tap changing on the GSP transformers. Transformers at Primary distribution substations are similarly equipped with automatic on-load tap changing equipment, effectively controlling voltage on the HV distribution system. Control of the LV system voltage is facilitated via off-load tap changing equipment on Secondary distribution transformers whereby taps must be changed manually when required and only when the transformer is de-energised.

Transformer Automatic Voltage Control

Automatic voltage control schemes are designed to maintain the voltage of the 33kV busbars at 132/33kV substations and the 11kV busbars at 33/11kV substations at or near to their respective nominal values. The schemes employ on-load-tap-changing transformers and use negative reactive compounding voltage control. Negative reactance compounding reduces circulating reactive power flows and tends to keep transformers operating in parallel at the same tap position.

Power Factor Correction

Reactive power increases losses and can affect voltage regulation and the operation of voltage control schemes. Negative reactance compounding is sensitive to power factor (the controlled voltage rises or falls as the power factor becomes more leading or lagging with respect to the power factor assumed to calculate the control relay settings). It is therefore advantageous to reduce reactive demand by suitable power factor compensation. This should be applied as close as possible to the specific load or embedded generation.

Voltage Regulations

In accordance with The Electricity Safety, Quality and Continuity Regulations 2002 (which replace the Electricity Supply Regulations 1988), the voltage supplied to customers must not, other than in exceptional circumstances, vary from the declared value by more than the values indicated in Table 2 below.

Table 2: Declared voltage ranges

Declared Voltage	Variation in Voltage from that Declared
LV	not exceeding 10 per cent above or 6 per cent below
HV	not exceeding 6 per cent above or below
33kV	not exceeding 6 per cent above or below
132kV	not exceeding 10 per cent above or below

2.2.2. System Faults and Protection

The power system must be able to protect itself in instances where faults occur. Power system faults are broadly classified based on duration i.e. transient or permanent. Transient faults are the most common type of faults experienced e.g. a tree branch coming into contact with an overhead conductor. A fault is considered permanent if it cannot be cleared by the power system protection and manual intervention is required e.g. a cable is damaged during ground excavation.

Regardless of type, when a fault occurs on the power system, all generation equipment and rotating machines i.e. generators and motors, contribute to the fault current. Fault current arising from the occurrence of a fault must be interrupted by the circuit breaker(s) controlling that circuit. Each circuit breaker required to clear the fault from the system must be capable of interrupting the maximum predicted fault current that is likely to flow at that point. In addition to this "break" duty, circuit breakers also have a "make" duty requirement which is the capability to energise a circuit which has been faulted or earthed. The maximum predicted fault current on any circuit or at any busbar can be calculated using this information. The method we use to calculate system short circuit fault levels is described in Section 2.4.4. Typical planning limits for fault currents on the SP Manweb system are outlined in Table 3. These values are the design limits and any connection causing these design limits to be exceeded will require the provision of fault level mitigation measures.

Table 3: System fault level break limits

System Voltage	Three Phase Symmetrical Short Circuit Current		Single Phase Short Circuit Current	
	MVA	kA	MVA	kA
132kV	4,570	20	5,700	25
33kV	1,000[15]	17.5	240	4.2[16]
11kV	250	13.1	250	13.1
6.6kV	150	13.1	150	13.1
6.3kV	143	13.1	143	13.1

2.2.3. Power Quality

Voltage deviations occur on all power systems and can be a result of a number of incidents. The most common causes of voltage deviation are described below. The increasing sophistication, sensitivity, and dependence on computers and computerised process control equipment have greatly increased the impact of these voltage deviations on customers. Particularly affected are major process and service industry customers who are vulnerable to loss of production as a result of disturbances on the supply system which last less than a second. We have fault recorder devices located around the system that typically capture data on fault dates and times, fault duration and the severity of voltage depression. This information is used to ensure that high quality supplies are delivered to customers and enables us to assist customers in their understanding of their internal protection requirements and advise on methods of minimising exposure to these incidents.

[15] Some of the SP Manweb 33kV network is limited to 750 MVA due to legacy switchgear, however this is being migrated to a 1000 MVA planning limit as the system is developed.

[16] The 33 kV system is resistance earthed (via earthing transformers on the transformer 33kV tails and earthing resistors). The single-phase earth-fault current is usually designed to be 1 p.u. on the transformer rating. For example, in Manweb network with four units of 60 MVA grid transformers in a BSP group, the design single-phase earth fault current would be 4*60MVA/(sqrt(3)*33kV) = 4.2kA.

While these incidents cannot be eradicated completely, our business strategy is to deliver continuous improvement in the Quality of Supply to customers.

Flicker

Voltage flicker refers to rapid variations in the voltage level on a distribution system, which may be caused by dynamically changing network loads, frequent switching operations and cyclic variations in embedded generator output currents.

Voltage Step Changes

Voltage step changes occur due to load and generation variations, the operation of tap changers and when the network is re-configured.

Voltage Dips

Voltage depressions, or dips, generally occur due to faults either on the customers own installation, other customer installations, or in the public distribution system due to insulation failure, 3rd party incidents or weather conditions. These are largely unpredictable and there are no specific statutory or licence requirements related to voltage dips.

Short / Long Term Interruptions

Short/long term interruptions are usually due to network faults and the associated auto-reclose or sequence switching that follows. Such interruptions are reasonably infrequent, occurring typically a few tens of times annually. Approximately 35% of the interruptions had a duration less than 15 seconds for networks below 132kV and no interruption less than 60 seconds on networks of 132kV and higher. Occasionally, interruptions may last longer than a minute and it is difficult to give exact durations as they are usually weather related, or due to other external causesl.

Spikes and Surges

Voltage transients or spikes on the supply system are excursions from the normal sine wave value. They mainly affect the LV system and are of very short duration. Typically, they vary from 100 V to 6,000 V and last less than a few milliseconds. Typical causes are the operation of fuses, capacitors, opening of contactors, switching of motors or household appliances. Such spikes are mainly produced by the customers' own installations and are rapidly attenuated, rarely penetrating through the distribution transformer.

Voltage Unbalance

Unbalance in a three phase supply is normally attributable to unbalanced loads and/or impedances. We minimise these unbalances by careful planning, design and construction of the distribution network. The major cause of imbalance is from the single phase loading of three phase rural overhead lines.

Harmonics

Any non-linear device drawing current from or injecting current into the power system will introduce a harmonic current component which will show as distortion of the voltage waveform. Typical sources of harmonic current are:

- Converter equipment, i.e. inverters, TVs, switched power supplies, wind turbine generators. These can all contain large inverters, ranging from 30-100% of their rating;
- Magnetic devices, i.e. transformers; and
- Non-linear loads, i.e. arc furnaces, DC electrolytic processes.

Power Quality Regulations

The Distribution Code for GB places obligations on customers regarding their impact on the system quality of supply. In addition, it requires their installations comply with the following industry standards:

- Engineering Recommendation G5/5: Planning levels for harmonic voltage distortion and the connection of non-linear equipment to transmission and distribution systems in the United Kingdom.
- Engineering Recommendation P28: Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom.
- Engineering Recommendation P29: Planning limits for voltage unbalance in the United Kingdom for 132kV and below.

Copies of the Engineering Recommendations and Technical Specifications specified in Annex 1 and Annex 2 of the Distribution Code, including those mentioned above, can be downloaded free of charge from the distribution code website[17].

2.2.4. Supply Information

Phase Relationships

The vector grouping and phasing at each voltage level follow a standard relationship so that operational parallels can be made between different parts of the Distribution Network that operate at the same voltage.

The angular relationship between the voltage vectors of systems at different voltage levels is defined by the clock-face convention. The 400kV, 275kV and 132kV systems are all in phase with each other. The red phase is the reference vector at transmission voltages and is considered to be at twelve o'clock.

Standard 132/33kV transformers are of vector group Yd1, resulting in the yellow phase vector on the 33kV busbar being at one o'clock with respect to the reference. Standard 33/HV transformers are of vector group Dy11 resulting in the yellow phase vector on the HV busbar being at twelve o'clock with respect to the reference. Standard HV/0.4kV distribution transformers will be of vector group Dy11, resulting in the yellow phase vector on the 0.4kV busbar being at eleven o'clock with respect to the reference.

[17] Distribution Code Annex 1 and Annex 2 Documents: http://www.dcode.org.uk/annexes/

The traditional standard phase relationships are shown in Figure 2 below.

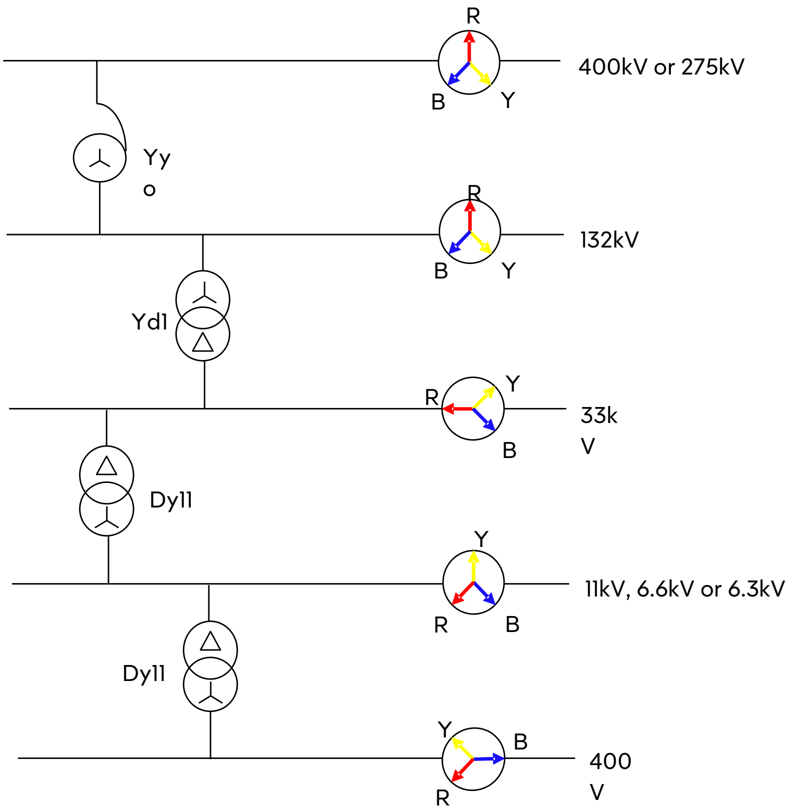

Figure 2: Traditional standard phase relationships

Historically the phase sequence for all voltage levels is represented vectorially by the R-Y-B anti-clockwise rotation. However, exceptions to these standards exist, particularly in the Merseyside area of the SP Manweb distribution network, where the North Mersey and Liverpool areas operate on a non-National Standard Phase rotation system at 33kV, HV and LV.

Phase colours

The UK is harmonised with the EU phase colour codes and all new installations must have the following phase colour codes applied (Figure 3 below).

	Earth (CPC)	Neutral	Line 1	Line 2	Line 3
OLD	**Green/Yellow**	**Black**	**Red**	**Yellow**	**Blue**
	Earth (CPC)	Neutral	Line 1	Line 2	Line 3
NEW	**Green/Yellow**	**Blue**	**Brown**	**Black**	**Grey**

Figure 3: EU phase colour codes

2.3. The Distribution System

The National Grid transmission system operates at 400kV and 275kV to provide a secure supply of electricity to customers with large or special demands, and to GSPs i.e. the exit points to the distribution system.

The SP Manweb distribution system is configured as described previously in Section 1.4 and operates at 132kV, 33kV (EHV), 11kV, 6.6kV, 6.3kV (HV), and 400/230 volts (LV). Key statistics for the SP Manweb system are provided in Section 1.4 and schematic diagrams of the Primary distribution system have been provided in Section 2.3.3.

Authorised developments of the Primary distribution system to the end of the five-year period are outlined in Part 4: Development Proposals. Please note that Condition 39 of the Electricity Distribution Licence requires us to restrict the use of certain information in connection with developments of a commercial or confidential nature which may distort competition. In order to comply with this obligation, this LTDS does not therefore include details or mention of any third party development until such times as the schemes are authorised by way of a Connection Agreement.

2.3.1. Distribution System Design Philosophy

The design of a distribution system requires careful consideration to balance cost with customer service. Over-design of a system can lead to poor utilisation and higher costs while under or ineffective design can result in reduced quality of service for customers, and in extreme cases, possible non-compliance with the Distribution Code and Electricity Distribution Licence.

The distribution system is therefore designed to be safe, reliable, economical, and efficient whilst also taking into account environmental considerations and sustainable development. The design must seek to strike a balance between quality and security of supply to customers, environmental protection, social equity and economic development, subject to minimum standards of security set out in the Distribution Code.

The SP Manweb system operates with a high utilisation factor and low maintenance requirement, using standard equipment, voltages, and phase relationships. Generally, only approved standard equipment, voltages and phase relationships will be accepted in the design of our distribution network. The use of standard equipment has many benefits including a reduction in operating costs, through reduced equipment stocks and strategic spares, minimisation of training for operational staff on new equipment and improvements in system performance. Extensions and modifications to the distribution system must take into account the existing system configuration such that design standards are maintained throughout. Any economic assessment of alternative designs is always based on whole-life costs and considers losses and security of supply performance.

Distribution systems have evolved over an extended period of time and, due to the relatively long life of power distribution assets which can be in excess of 40 years, many legacy practices continue to exist. These features have a bearing on present and future design practices. It is important to make best use of existing assets as well as to protect the reliability, integrity, and performance of the system.

2.3.2. Design Principles and Standards

Our SP Manweb network is unusual in GB as the majority is an interconnected or "meshed" design. This means power can flow through multiple routes to the point of use. By comparison, most GB distribution networks have a traditional radial design, where power typically has only one possible path. The interconnection extends across our entire 132kV and 33kV network and over half our HV and LV network.

The origins of the SP Manweb interconnected design can be retraced to the period shortly after the electricity industry was nationalised in 1947, and it was developed and expanded over the next 30 years and continues to be modified, developed and extended today.

The design methodology varies significantly from the traditional industry network design which relies upon duplicate radial networks, emanating from bulk-power transformations. The SP Manweb philosophy is based on high transformer utilisation, where smaller single transformer substations supply power into an interconnected mesh where standard cable sizes are used throughout. Each voltage layer provides support to the voltage layer immediately above (LV, HV, EHV and 132kV), offering a fully integrated and interconnected network. More detail on the protection arrangements and designs at each voltage level is included in subsequent sections of this LTDS.

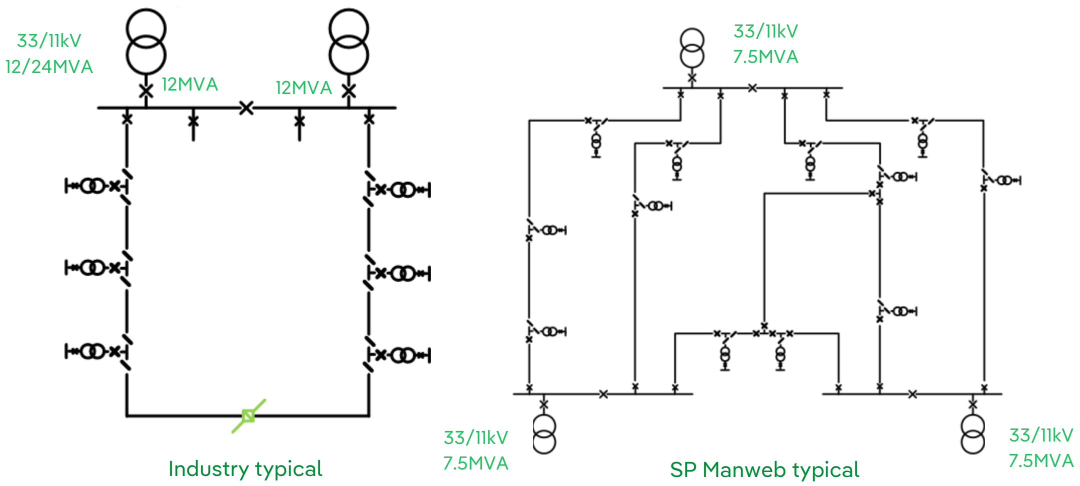

Table 4: Proportion of SP Manweb network by configuration

% Network and Type	Description	Area/Geography
55% Fully interconnected, with unit protection	• Solid interconnection at 33kV, HV, LV • Full unit protection • Standard equipment ratings • 75-85% asset utilisation	• Mainly urban • Mainly underground • Liverpool • Wirral
23% Fully interconnected, without unit protection	• Solid interconnection at 33kV, HV • Less interconnection at LV • 70% asset utilisation	• Merseyside • Cheshire • Wales • Urban/rural
22% Standard Radial	• Radial across all voltages • 50% asset utilisation	• Mainly rural • Wales • Cheshire

The design philosophy of the SP Manweb network delivers the following benefits:

- better levels of system performance and reliability (no customer supplies are lost for over 95% of the faults experienced on our 33kV network);
- higher levels of asset utilisation as compared to conventional network designs; and
- very flexible in accommodating new customer requirements.

The unique nature of the SP Manweb network offers the best network reliability in GB. However, the downside to this is that it is more expensive to run. Our approach is to minimise the additional cost and maintain the benefits to customers of having this type of network.

The SP Manweb interconnected distribution networks are planned and operated to withstand the sudden loss or withdrawal from service of any Primary circuit without any loss of supply to customers or an unacceptable deviation in voltage or frequency. This assumes an intact system with no pre-existing circuit outages. The distribution outage maintenance programme is carefully planned and controlled to ensure that operational security standards are not infringed. Continuous outages are not normally permitted during the winter months of November to February.

The technical and design criteria and procedures applied in the planning and development of the distribution system are detailed within the Distribution Code of Licensed Distribution Network Operators of Great Britain. Under Condition 15 of the Electricity Distribution Licence Document, the SP Manweb system must also comply with the provisions of the GB Grid Code.

Security of Supply

A fundamental review of ENA Engineering Recommendation P2 has been undertaken by the Distribution Code Review Panel (DCRP) through the Energy Networks Association (ENA). This review has concluded with the that publishing of EREC P2 Issue 8 in February 2023.

The SP Manweb system has been designed in compliance with Engineering Recommendation P2 Issue 8 “Security of Supply”. Engineering Recommendation P2 Issue 8 describes the appropriate level of security required for distribution networks classified in ranges of group demand. This is the minimum standard applied for engineering security, although individual customers e.g. commercial or industrial, may desire a higher or lower “personalised package”. In general, compliance with P2 Issue 8 enforces duplicate supplies to Grid and Primary substations, and HV networks with a switched alternative arrangement.

Voltage Disturbance and Harmonic Distortion

To limit the effects of distortion of the system voltage waveform, the harmonic content of any load shall comply with the limits set out Engineering Recommendation G5/5 “Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Equipment to Transmission and Distribution Systems in the United Kingdom”.

The requirements of Engineering Recommendation P28 “Planning Limits for Voltage Fluctuations caused by Industrial, Commercial and Domestic Equipment in the United Kingdom” shall also be met. Voltage unbalance between phases shall comply with the levels specified in Engineering Recommendation P29 “Planning Limits for Voltage Unbalance in the United Kingdom”.

While there may be parts of the distribution system where harmonic levels are approaching the limits specified within Engineering Recommendation G5/5, we are not presently aware of any site where those limits may routinely be exceeded. We deploy power quality monitoring equipment to identify potential harmonics, flicker and voltage unbalance issues both as a commitment to customers connected to the network and as part of the connection process for new customers.

Detailed design policy is contained within the following sections.

Environmental Planning

We recognise that our installations, whether overhead or underground, can have an effect on the environment, and we seek to minimise this via careful planning and execution of projects.

Nevertheless, local interest in electricity distribution operations can in some cases lead to delays in obtaining the relevant planning and environmental consents. We therefore maintain a dialogue with regional government, local authority and government agency representatives to obtain their support. This approach enables those with responsibility for making decisions to have an improved understanding of the industry's needs. It also provides the opportunity to make them more aware of the schemes included in this LTDS.

Improving the confidence of regional partners is aided by us recognising the importance of conserving and enhancing environments potentially affected by future works, as set out in our Preservation of the Amenity Statement (in accordance with Schedule 9 of the Electricity Act). The approach is to carefully work within environmental limits and bring about improvements where opportunities arise. The same environmental standards are expected of developer partners.

2.3.3. Typical Distribution Networks and Configurations

The distribution networks in our SP Manweb licence area cover several voltage levels and also across various geographical areas and population types i.e. urban and rural areas. There are typical configurations and topologies for each type of network e.g. urban EHV networks across the licence area will have a typical design, as will rural LV networks. The following sections describe these different network configurations, typical at each voltage level, for urban and rural areas. Typical protection, automation and control philosophies for each voltage level and network type are also detailed.

132kV EHV Primary Distribution System

For a heavily interconnected network such as that in our SP Manweb area, extensive system analysis is performed to determine the number of Supergrid transformer (SGT) connections, the system configuration and the operating regime of the 132kV network. This ensures that supply security is maintained and short circuit design limits are not compromised. By their very nature, 132kV networks are specialised and the design of the 132kV network is undertaken on a case-by-case basis.

The 132kV network is supplied from the National Grid transmission system through their 400/132kV or 275/132kV SGTs at GSP substations. The SGTs are normally connected to the SP Manweb system by National Grid owned 132kV circuit breakers at the GSP substations.

The SGTs are autotransformers that have solidly earthed neutral connections and on-load tap changers to control the 132kV voltage. Site-specific 132kV target voltages are agreed with National Grid.

SP Manweb normally owns the 132kV busbars within the GSPs. The exception is where National Grid provides connection to another party, in such cases National Grid will own the 132kV busbar.

The 132kV busbars within GSPs shall be of double busbar configuration. Typically, there will be two main sections of busbar (with circuit breaker coupling), and two reserve sections of busbar with motorised load break disconnector coupling. A single main-reserve bus coupling circuit breaker is employed where there are less than seven circuits (including SGTs) and two main-reserve bus coupling circuit breakers where there are seven or more circuits.

A typical 132kV network is illustrated in Figure 4 below.

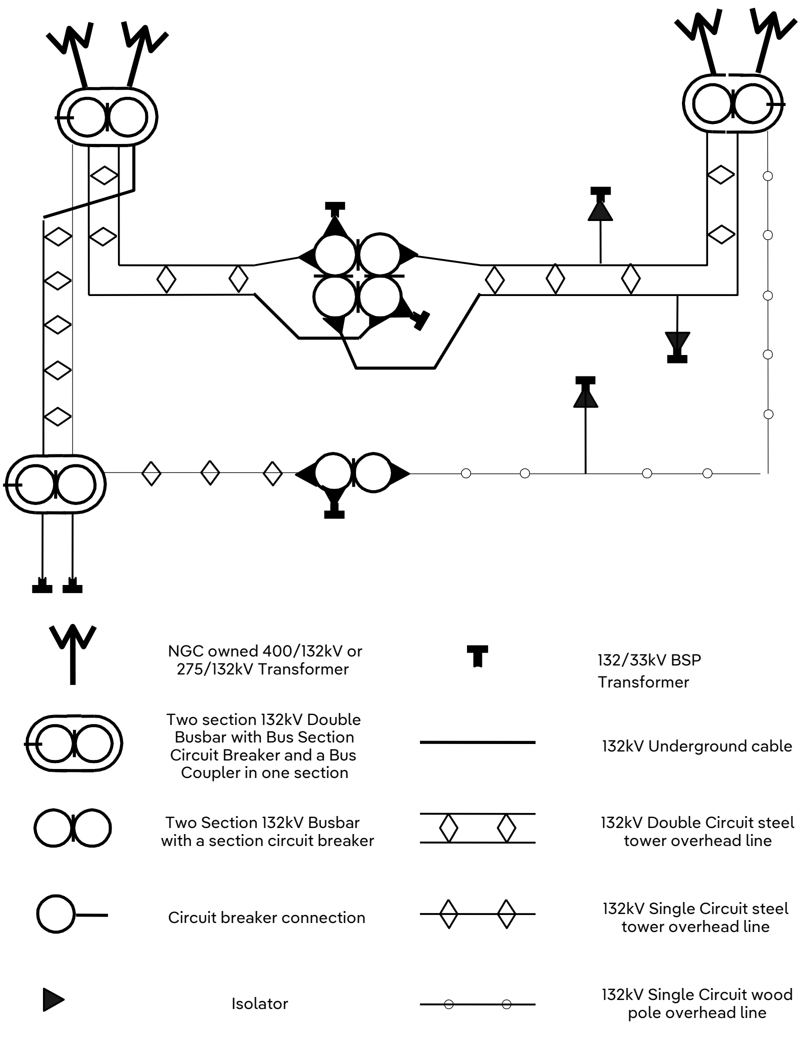

Figure 4: Typical 132kV network in SP Manweb area

Care needs to be taken in the selection of 132kV switchgear at a GSP because the high value of the source X/R ratio of the 132kV in-feed may lead to a longer time decrement of fault current than switchgear is usually designed to accommodate.

The 132kV network comprises of sections of underground cable or overhead lines (supported by steel towers or wood poles) or a combination of both. The circuits interconnect and/or provide connections to BSP substations, i.e. 132/33kV substations.

132kV protection policy

Two levels of protection (main and back-up) are provided to ensure that no single failure of a protection device and associated equipment will result in a failure to clear a fault from the Primary system. Each protection system discriminates between faults within its protection zone and initiates the opening of only those circuit breakers required to isolate the faulted apparatus from the Primary system. The protection sensitivity can detect earth faults including a fault resistance of up to 100 ohms where appropriate.

For phase-phase and phase-earth faults, the main protection which initiates fault clearance by a circuit breaker operates in less than 40 milliseconds. However, main protection operating times are not less than 10 milliseconds to comply with IEC 56 for circuit breakers. For main protection, the target fault current interruption time of the main fault in-feeding circuit breakers from fault inception to arc extinction is a maximum of 120 milliseconds.

33kV EHV Primary Distribution System

The Primary distribution system is a group of circuits that provides supplies to Primary substations and customers with an EHV point of supply. These circuits also offer the provision of emergency interconnection between BSPs. The circuits comprise sections of underground cable or overhead line (supported by steel towers or wood poles), or a combination of both.

The 33kV network is supplied from the 132kV network at BSP substations utilising Grid transformers of a standard size and vector group, as detailed in Table 5. Each transformer has an on-load tap changer, which is employed with an automatic voltage control (AVC) scheme to maintain 33kV system voltages. Details of individual transformer impedances are given in Appendix 2: Transformer Data (Table 2).

Table 5: Rating of standard Grid transformers

Nominal Ratio	Winding Configuration	Rating (MVA)
132/33kV	Yd1	45 (No longer standard size for new equipment)
132/33kV	Yd1	60
132/33kV	Yd1	90

To achieve high utilisation of the transformers, they are operated in parallel with those at other BSP substations through the interconnected 33kV network. The short circuit design level of the network restricts the number of transformers that can be operated in parallel. To avoid exceeding the short circuit design level at BSP substations where there is more than one transformer, they will usually be operated in parallel with different groups of transformers. In some circumstances, as an economic means of network extension, it may be necessary to employ transformer or circuit reactors to control short circuit levels or to improve load sharing.

AVC schemes employ negative reactance compounding to ensure the tap changers on each transformer remain synchronised. The AVC equipment is normally set to maintain the transformer secondary voltage within +/ 1.75% of the nominal secondary voltage.

The neutral point of the Primary winding of the BSP transformer is solidly earthed, whilst the 33kV system neutral earth is provided by an auxiliary 33/0.4kV transformer and earth resistor which are connected close to the Secondary transformer bushings.

Customers requiring a high capacity (usually above 15 MVA) are normally connected to the 33kV network via metered circuit breakers.

33kV protection policy

Two levels of protection equipment, main and back-up, are provided to ensure that no single failure of a protection device shall result in a failure to clear a fault from the Primary system. Each protection system is capable of discriminating between faults within its protection zone and initiates the opening of only those circuit breakers required to isolate the faulted apparatus from the Primary system. The protection sensitivity is capable of detecting earth faults including a fault resistance of up to 100 ohms.

Protection operating times are not less than 10 milliseconds to comply with IEC 56 for circuit breakers. For multi-phase faults and earth faults the main protection which initiates fault clearance by a switching device operates in less than 100 milliseconds. This is to achieve a total fault clearance time, from fault inception to arc extinction, of 200 milliseconds.

33kV System Automation

One of the many benefits of the interconnected 33kV network design is that the unit protection schemes operate so as to disconnect the minimum section of network required to isolate the faulted apparatus from the system. In rural areas, SCADA facilities at all 132kV and 33kV substations permit remote operation of key circuit breakers from the Network Management Centre (NMC). There is therefore no significant advantage to be gained by using automation on this type of network.

Urban 33kV Networks

The circuits in a 33kV urban network consist mainly of standard sized underground cables that form interconnections between BSP substations. The network is generally operated in interconnected groups of two to four BSP transformers with its exact configuration and operating regime determined by network analysis. Primary substations are either connected into the 33kV interconnector circuits, using either ring main units or multi-panel switchboards, or by radial circuits from BSP substations.

For security purposes it is desirable that transformers operated in a group, be supplied from different 33kV interconnectors. Figure 5 shows a typical 33kV urban network. The protection applied on 33kV feeders is unit type protection utilising pilot cables, although as a minimum, the 33kV circuit breaker controlling a transformer feeder shall be equipped with three-phase instantaneous overcurrent elements and high speed earth fault protection. Back-up systems for each 33kV feeder circuit breaker are provided using three-pole Inverse Definite Minimum Time (IDMT) overcurrent and single-pole earth fault protection.

Where ring main unit connection of the Primary substation is employed, the transformer will be connected to a ring switch and the network connections are made to the other ring switch and circuit breaker. In these cases, the unit protection zone will include the circuit from the remote circuit breaker connection, the ring main unit and the Primary transformer. Any in-zone fault will then cause isolation of the zone at the remote circuit breaker, the local 33kV feeder circuit breaker and transformer HV circuit breaker. Disconnection of the transformer in such circumstances will not generally result in any disconnection of customers, as supplies will be maintained by HV circuit interconnection with other Primary substations.

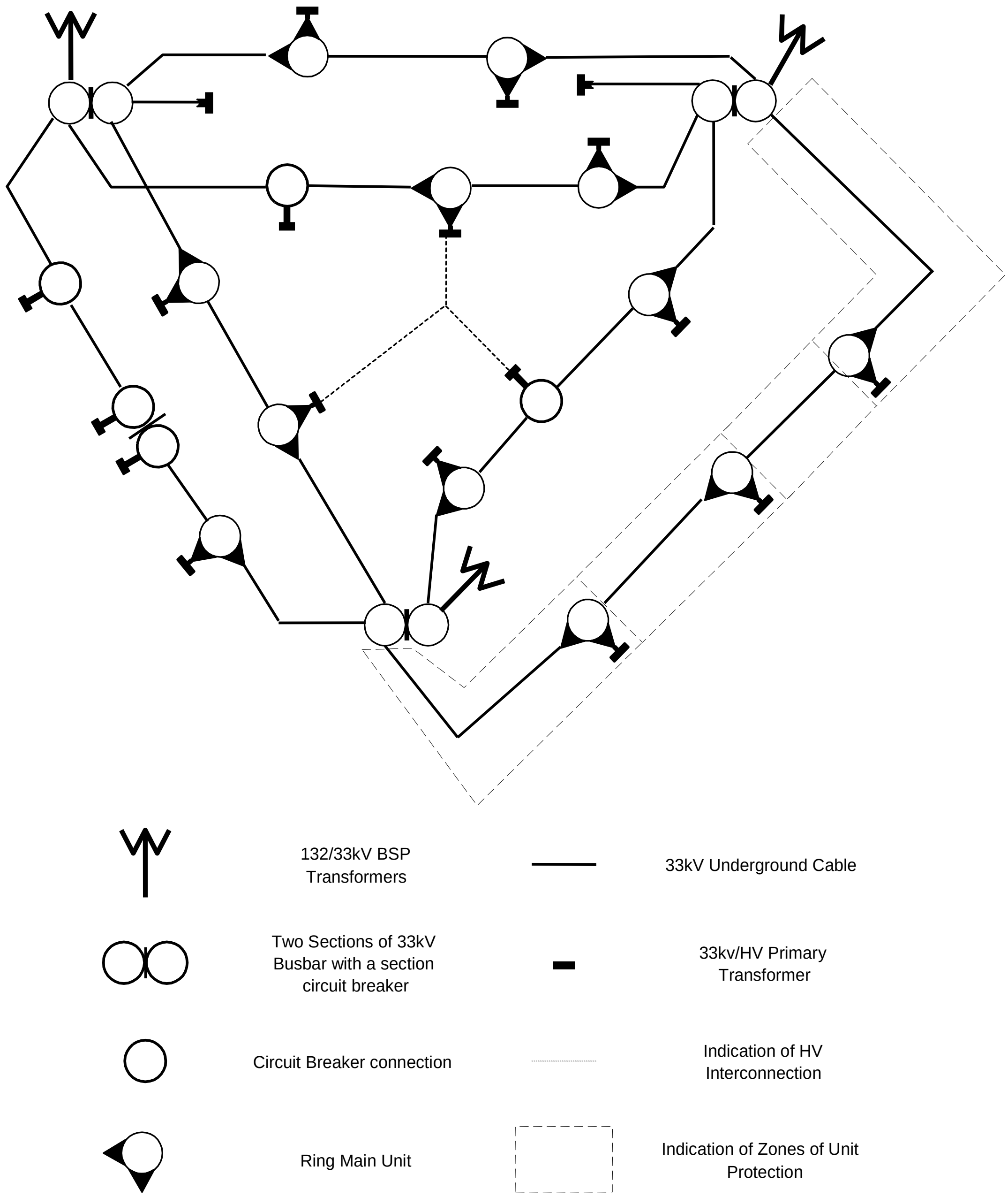

Figure 5: Typical 33kV urban network

When the connection of the Primary substation is made by a multi-panel switchboard, all circuits' connections are made to a circuit breaker and the transformer connection is made to a circuit breaker, or in some cases a ring switch. In these circumstances the unit protection zones will only include the interconnectors between substations. Dedicated transformer and busbar protection will be provided.

Rural 33kV Networks

The circuits in a 33kV rural network are predominantly overhead lines of wood pole construction that form interconnections between BSP substations. They are entirely of three-phase construction but without any earth conductor. The 33kV interconnectors operate without any open points on the circuit so as to parallel BSP transformers

Primary substations are connected either into the 33kV interconnectors or by radial connections from BSP substations. All Primary substations are ground mounted and will include either an outdoor compound to house 33kV circuit breakers or a building to house a multi-panel switchboard. Switchgear in the outdoor compound is configured so as to provide circuit breaker connections to the network feeders. When there are no more than two network feeder connections, the Primary transformer will normally be connected by a load break isolator. In those cases when there are more than two feeder connections, or where a multi-panel switchboard arrangement is employed, the transformer will be connected to a circuit breaker. Figure 6 shows a typical 33kV rural network.

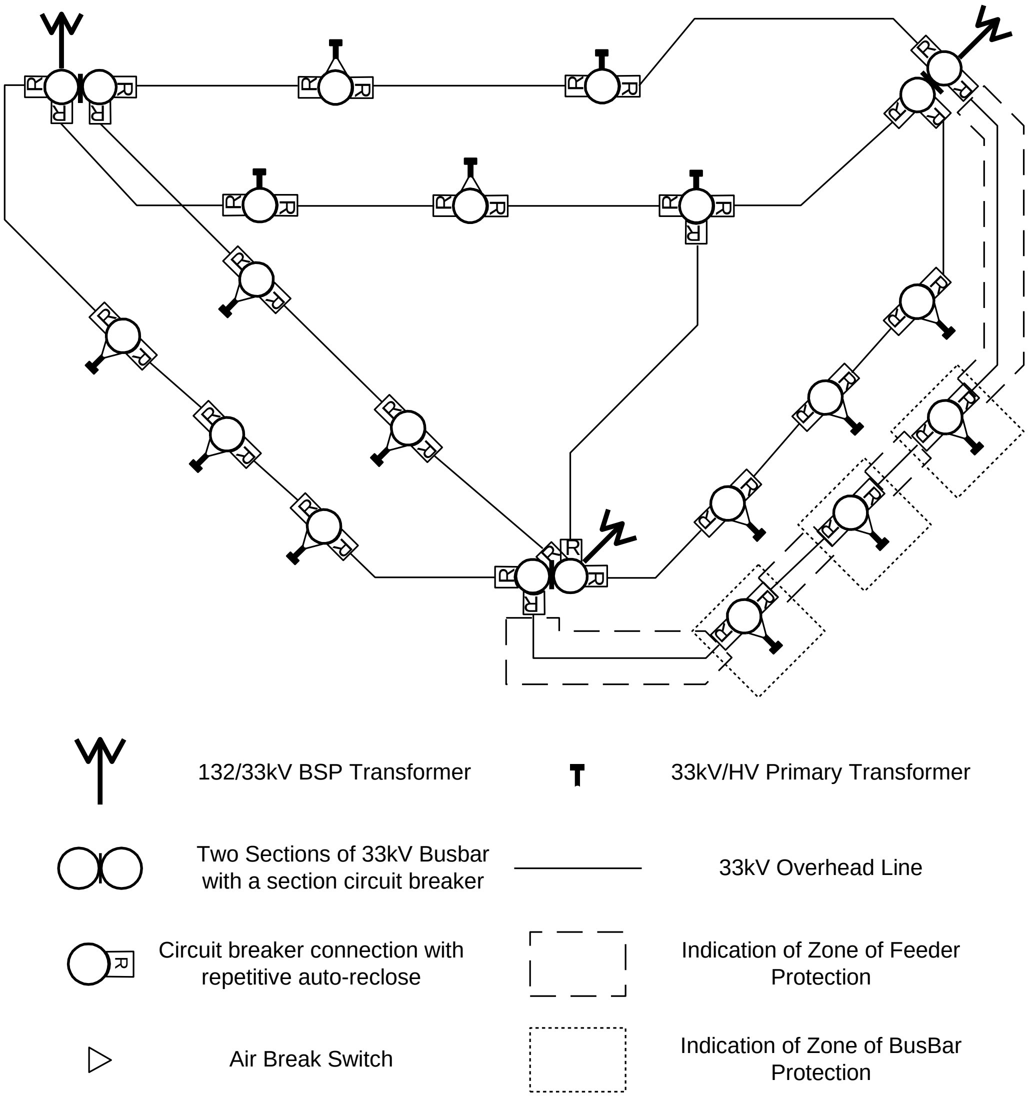

Figure 6: Typical 33kV rural network

All 33kV (and 11kV) overhead lines are constructed to our specifications, which ensure that network resilience is maintained in weather conditions specific to the local geography. Following legislation amendments in 2006, there is an increased focus on improving rural overhead line network resilience during severe weather events to minimise the impact of severe storms on customers. Compliance with this legislation amendment will require network operators to actively manage vegetation to ensure that network security is not compromised by trees within falling distance of the conductors.

Unit protection schemes are employed to disconnect faulted 33kV circuits. The zone of protection is the circuit between Primary substations or Primary substation and BSP. Unit protection relies on a communication channel between each end. The conversion of the public telephone network from PSTN to IP technology, however, means that it is becoming increasingly difficult to establish unit protection schemes. Protection schemes going forward are likely to be a mixture of both unit and non-unit arrangements with some utilising pilots and others employing other communication methods.

Busbar protection and transformer protection are provided by a common scheme for those substations having no more than two feeder connections to outdoor circuit breakers. Separate busbar protection and transformer protection schemes will be used for all other outdoor circuit breaker arrangements or multi-panel switchboard installations.

When the Primary transformer is operated in parallel with other Primary transformers, protection schemes will be selected to ensure no faulted section of 33kV network that has been isolated by circuit breaker operation can be energised by the HV interconnection.

All new 33kV circuit breakers controlling circuits of overhead line construction are fitted with auto-reclose equipment. Existing installations will be modified to include auto-reclose as and when they become due for planned replacement or modernisation. The auto-reclose equipment is applied on a per circuit basis and controls all circuit breakers within the zone of protection. The operating mode for all auto-reclose equipment is delayed single-shot auto-reclose. This enables many transient faults to be cleared automatically, thereby improving network performance.

HV Secondary Distribution System

The secondary distribution system provides supplies to Secondary substations and to customers with an HV connection. The HV system also provides interconnection between Primary substations. HV circuits comprise sections of underground cable or overhead line, or a combination of both. While some areas of the HV system in Merseyside continue to operate at 6.6kV and 6.3kV, the bulk of the HV distribution system operates at 11kV.

The HV network is supplied from the 33kV network at Primary substations utilising standard transformer sizes and vector groups, as outlined in Table 6. Details of individual transformer parameters and impedances are given in Appendix 2: Transformer Data (Table 2). Each transformer has an on-load tap changer, which is employed with an AVC scheme to maintain HV system voltages. The AVC scheme employs negative reactance compounding to ensure that the tap changers on all transformers operating in parallel remain synchronised. This ensures efficient load sharing and minimises circulating current. The AVC equipment is normally set to maintain the transformer secondary voltage within limits of +/- 1% of the voltage set point. The target voltage is normally set to 11kV at the Primary substation HV busbar.

Table 6: Details of standard Primary transformers

Nominal Ratio	Winding Configuration	Rating (MVA)
33kV/11kV	Dy11	4 (No longer standard size for new equipment)
33kV/11kV	Dy11	7.5
33kV/11kV	Dy11	7.5/10

The neutral point of the secondary winding of the Primary transformer is solidly earthed. Customers requiring connection capacities above 1 MVA are connected to the HV network via metered circuit breakers or via a ring main unit equipped with a DC trip and a CT/VT metering unit.

Urban HV Networks

In urban areas Primary transformers are operated in parallel, through the interconnected HV network, with transformers at other Primary substations to achieve high utilisation of the transformers and circuits. The number of transformers that can be operated in parallel is restricted by the short circuit design level of the network. The interconnected groupings are shown in Figure 7 and Figure 8 below.

The network is almost exclusively constructed from standard size underground cables, which are arranged so as to interconnect Primary substations, and typically supply up to twelve HV/LV Secondary substations.

Secondary substations are connected to the interconnectors by one of two different HV switchgear configurations and an associated protection scheme. For the dense urban areas where extensive LV interconnection is possible a unit-protected design is employed. Substations conforming to this design are designated X-Type substations. The X-Type substation is an indoor (brick built) substation which houses a X-Type ring main unit, 500kVA HV/LV transformer, low voltage distribution fuse board (including an air insulated circuit breaker), Solkor unit protection relay panel, DC tripping battery and battery charger.

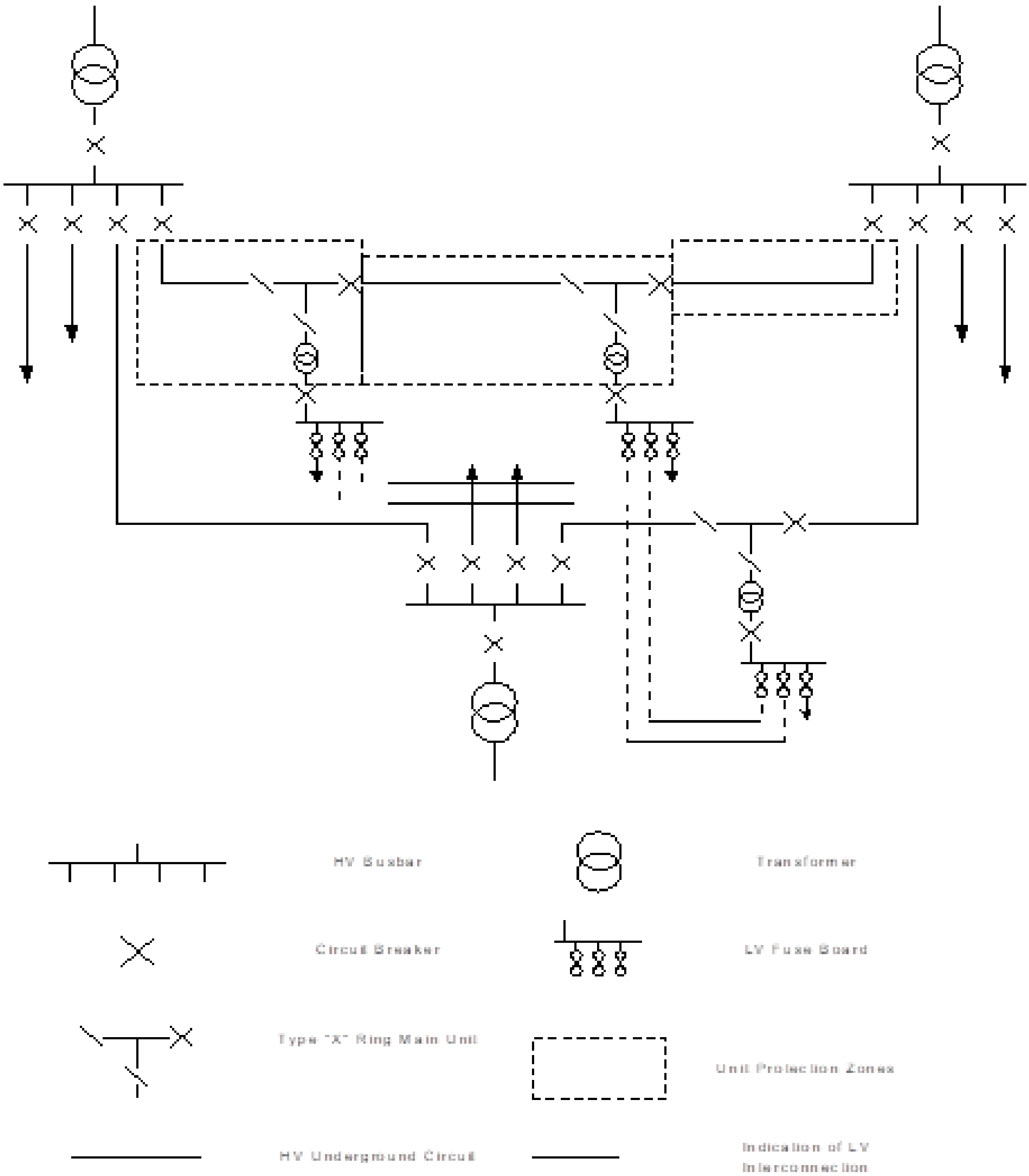

Figure 7: Typical HV urban unit protected network

The protection applied on 11kV feeders is unit type protection utilising pilot cables, and back-up systems for each 11kV feeder circuit breaker are provided using three-pole Inverse Definite Minimum Time (IDMT) overcurrent and earth fault protection.

The ring main unit is configured such that the transformer will be connected to a ring switch and the network connections are made to the other ring switch and circuit breaker. In these circumstances the unit protection zone will include the circuit from the remote circuit breaker connection, the ring main unit and the Secondary transformer. Any in-zone fault will then cause isolation of the zone at the remote circuit breaker, the local 11kV feeder circuit breaker and transformer LV circuit breaker.

Application of the X-Type design facilitates extensive LV interconnection, which can be configured such that it cross connects Secondary substations supplied from different HV feeders within the same group of Primary substations. Extensive LV interconnection, combined with the unit protected HV interconnection, facilitates high utilisation of transformers and circuits thereby reducing expenditure on new apparatus. It also provides the benefit, where there is adequate LV interconnection, of maintaining supplies when a faulted item of HV apparatus is disconnected by network protection. Figure 7 shows a typical HV urban unit protected network.

In sub-urban areas where the LV interconnection is not as comprehensive, a non-unit-protected design is employed. Substations conforming to this design are designated Y-Type substations.

The Y-Type substation can be indoor (i.e. brick or GRP) or an outdoor compound, which houses a Y-Type ring main unit, HV/LV transformer and LV distribution fuse board. Network connections are made from HV interconnectors between Primary substations to the ring main unit ring switches. On older installations, switch-fuse ring main units were employed. On new installations the transformer is connected to the ring main unit circuit breaker and the transformer is protected by time limit fuses.

In a similar manner to the unit protected networks, three-phase over current protection is installed at the Primary substation on each end of the HV interconnectors. Figure 8 shows a typical HV urban non unit protected network.

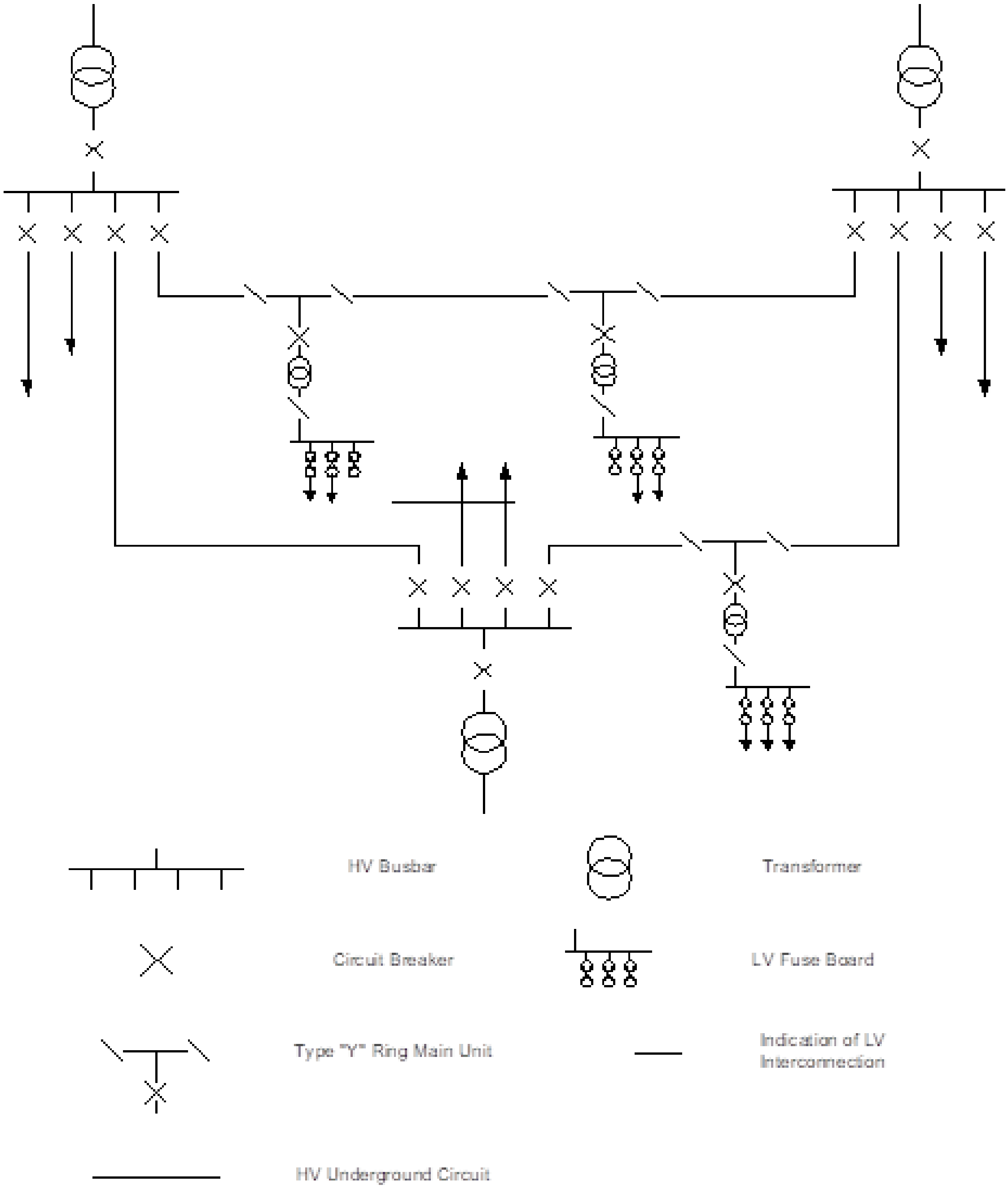

Figure 8: Typical HV urban non-unit protected network

Urban HV Network Automation

One of the many benefits of the urban HV interconnected network design using X-Type substations is that the unit protection schemes operate so as to disconnect the minimum section of network required to isolate the faulted apparatus from the system with no loss of supplies to customers. There is therefore no advantage to be gained by using automation on an X-Type network. In contrast, faults in semi-urban areas with Y-Type substation configurations affect customer supplies and generally require manual operation to restore alternative supplies.

We have been working to improve the performance of the distribution Y-Type and rural radial networks through the installation of additional protection zones, automation and tele-control of switching equipment. The objective is to limit the number of customer interruptions caused by any one fault and reduce restoration times.

Commissioning of additional protection zones which incorporate automation is continuing. These have been retrofitted to existing circuits. The circuits targeted were those with highest number of customers interrupted and largest densities of customers within a single protection zone. In future, all new or modified circuits supplying more than one thousand customers in Y-Type networks will be considered appropriate for the installation of mid-feeder protection and/or automation schemes.

Rural HV Networks

HV rural networks are of predominantly overhead construction and designed as a series of three-phase main lines with radial spur lines branched off. Radial spurs can be either three-phase or single-phase. Ground mounted substations and/or cable network may occasionally be included within the circuits. Although main lines run between Primary substations, they are operated radially utilising a pole mounted isolation device along the circuit route in the open position. Figure 9 shows a typical HV rural network.

All 11kV (and 33kV) overhead lines are constructed to SP Manweb specifications, which ensure that network resilience is maintained in weather conditions specific to the local geography. Following legislation amendments in 2006, there is an increased focus on improving rural overhead line network resilience during severe weather events to minimise the impact of severe storms on customers. Compliance with this legislation amendment will require network operators to actively manage vegetation to ensure that network security is not compromised by trees within falling distance of the conductors.

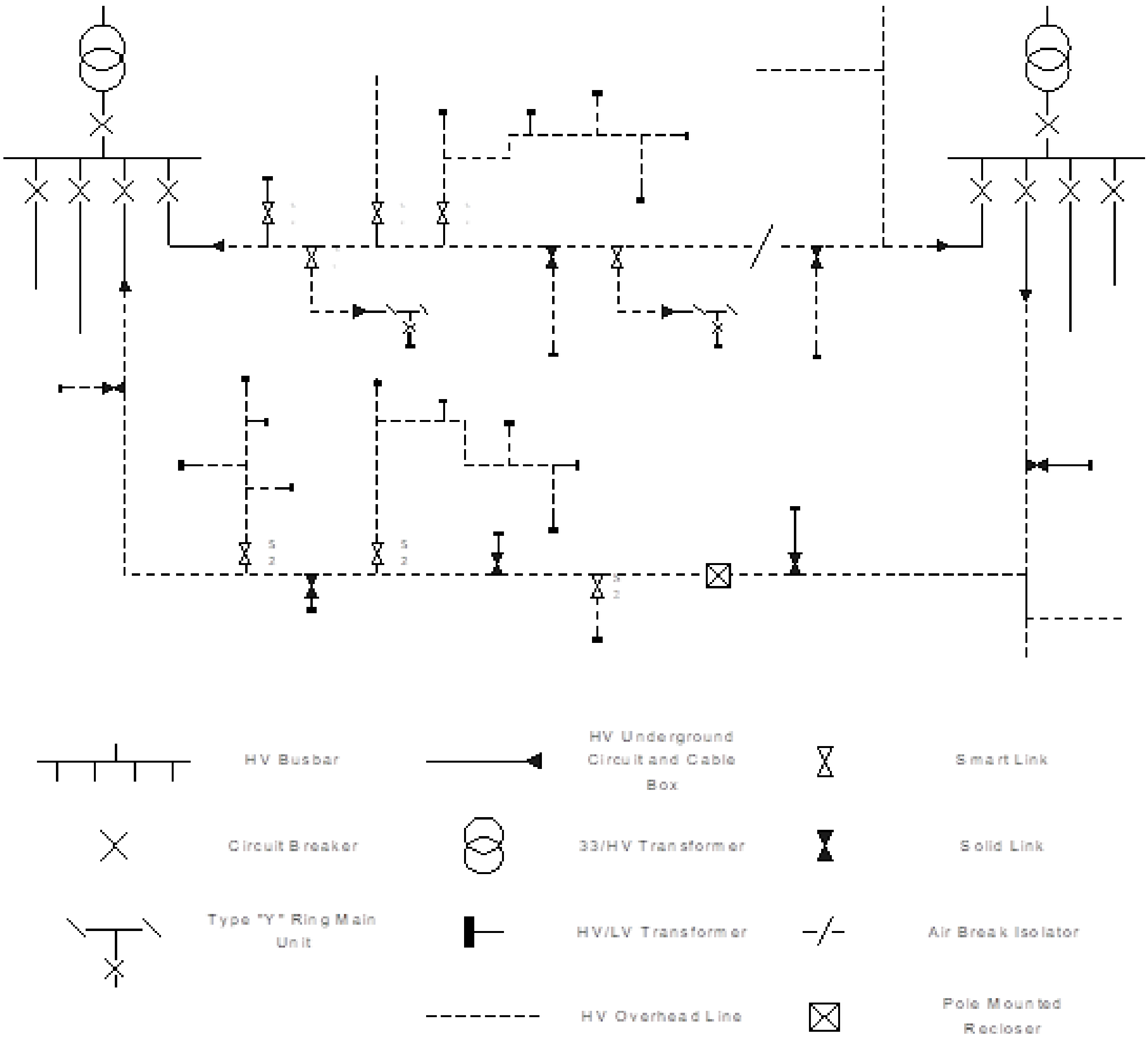

Figure 9: Typical HV rural network

The disposition of demand is such that an interconnected network is sometimes not geographically practicable, and the rural HV network is operated radially with tee-off branches to customers. The tee-off circuits have traditionally been protected by pole-mounted three-phase or single-phase expulsion fuses, but more commonly now by pole-mounted automatic sectionalisers.

Main lines connect Primary substations and are fed via non-reclosing, single-shot non-repetitive auto-reclosing, single-shot repetitive auto-reclosing or multi-shot repetitive auto-reclosing circuit breakers.

Rural HV Network Automation

On all new, replaced and refurbished overhead lines, the main lines are controlled via multi-shot auto-reclosing switchgear. This auto-reclosing switchgear is capable of a minimum of three trips to lock-out and may be ground mounted or pole mounted. It is SP Manweb practice to employ a reclose time of 10 seconds and reclaim time of 10 seconds. Protection settings are application specific.

Automatic sectionalisers discriminate between a transient and persistent fault by counting the passage of fault current during the auto-reclose sequence of the controlling switchgear. Sectionalisers operate during the dead time of the auto-reclose sequence after a pre-determined number of passages of fault current. They are only fitted to circuits protected by a multi-shot auto-recloser with minimum number of trips to lock-out being one more than the sectionaliser count.

Many overhead line faults are transient in nature due, for example, to wind activity or lightning. The application of the above overhead line protection policy improves system performance and network resilience under transient fault conditions and limits the number of customers disconnected under persistent fault conditions.

On rural HV feeders where load is situated some distance from the Primary substation and the network topology is suitable, an automation scheme will be applied. It is envisaged that these schemes will be similar to the urban equivalent described with two points on each circuit being automated, the normally closed point and normally open point. It is envisaged that this model will allow a generic automation system to be developed.

LV Distribution System

The LV network is supplied from the HV network at Secondary substations via fixed ratio, Dy11 transformers. The neutral points of the secondary winding of the HV/LV transformers are solidly earthed. LV circuits then provide supply to the vast majority of customers.

The Electricity Safety, Quality and Continuity Regulations 2002 require that the voltage at a customer's supply terminals be maintained within 230 V +10%, -6%. This is equivalent to the range 216 V to 253 V. Secondary distribution transformers have a standard no-load secondary voltage of 250V and off-load taps by which the secondary voltage may be varied by +/-2.5% and +/-5%.

High-Rupturing Capacity (HRC) fuses of an appropriate rating are installed at the substation connection of the LV circuits to provide protection against excess current whilst also ensuring discrimination with HV circuit and transformer protection schemes.

Connections are made to the LV circuits to provide supplies to small industrial, commercial, and domestic premises and street furniture. These connections are made in a manner that provides a balanced electrical demand across the phases.

Urban LV Networks

The LV urban network is constructed of standard sized cables and typically supplied by 500kVA transformers enclosed in a standard indoor substation.

Normally five LV cables emanate from an HV/LV substation originating at a distribution LV fuse-board. The cables are connected to form interconnectors between substations to achieve high utilisation of transformers/circuits and allow for the restoration of supplies under certain fault conditions.

HRC fuses within the substation will operate to disconnect faulted cables and will consequently de-energise those connections made to the circuit.

Rural LV Networks

Typically, low voltage networks in rural areas can be of three-phase or single-phase overhead construction, supplied by an HV/LV pole mounted transformer selected from a range of standard ratings.

Extensive development of the HV overhead network combined with the facility to match customer demands to individual pole-mounted transformer ratings has tended to limit the LV overhead network to distributing supplies to small groups of properties e.g. village areas.

SP Manweb policy states that bare wire LV overhead lines shall not be added to the system. New construction will be of Aerial Bundled Conductor (ABC) specification or underground cable.

2.3.4. SP Manweb Network Long Term Strategy

We keep the SP Manweb network design under review and for extensions to the network we consider whether we should extend the interconnected design approach or revert to a traditional radial design. However, there are a number of practical reasons that would make it very difficult to fully convert the SP Manweb interconnected network to a radial network. Full transition to a radial system would require new transformers and cables to be installed throughout the entire network at a cost of £5bn-7bn and would take 20-30 years. Independent reviews undertaken periodically have concluded that large scale conversion is not cost effective and would remove the embedded benefits that other DNOs are working to achieve.

We are at present considering the benefits of moving towards a hybrid network design at the “fringes” of the network where the benefits of a fully interconnected network are not as great, to allow network performance and costs to move towards national averages over the long term. We aim to reduce the gap with industry average costs, whilst maintaining and enhancing the benefits of interconnection where appropriate. This will enable us to develop a network that will facilitate a Net Zero future.

Our longer term aims are therefore to:

1. Transition the network where it benefits our customers
2. Provide network extensions at industry average costs
3. Enhance the benefits of interconnection

We aim to achieve this by developing an efficient innovative network, and we are at present trialling a number of innovation technologies to help us to achieve this.

2.3.5. Distribution System Trading Arrangements

Electricity demand varies from day to day and from hour to hour throughout the year, as illustrated by the 2023/2024 daily load curves shown in Section 2.3.7. In addition, generation and customer demand must be constantly matched. The diversity of generators and suppliers now established in the energy market requires that satisfactory trading arrangements be in place to facilitate the balance of generation and demand.

Trading Arrangements

In England & Wales, the New Electricity Trading Arrangements (NETA) were implemented on 27 March 2001. NETA takes a form similar to established commodity markets with forwards, futures, short-term bilateral and balancing markets.

The bulk energy market operates on the basis of bilateral contracts between generators and suppliers. Under the terms of our distribution licence, we are obliged to allow non-discriminatory access to all parties who wish to use the distribution system in order to facilitate their trades. The user will have connection and use of system agreements detailing their access rights and our responsibility is to deliver that service to the user. This enables each generator to meet their total contractual obligations from their portfolio of energy sources, and for each supplier to receive the energy from their contracted sources at contracted prices.

In the market environment, the responsibility for minimising the cost of energy production lies firmly with the generators.

The supply arrangements in our SP Manweb area entitle a supplier, wishing to supply premises in the SP Manweb area, to transfer the electricity required to meet the demands of their customers to the distribution system. The supplier may have their own generation or contract with another generator with appropriate generating capacity.

The rules governing competition in the electricity supply market are contained in the Balancing and Settlement Code (BSC). All licensees, including independent generators and electricity suppliers, are required to be a party to, and to comply with, the provisions of the BSC.

The BSC requires suppliers to use all reasonable endeavours to have in place adequate arrangements to obtain supplies of electricity to meet their requirements. Similarly, generators are required to use all reasonable endeavours to have in place adequate arrangements to supply their output.

Under the GB Grid Code, generators connected to the GB distribution network may be required to submit generation schedules to the NESO and may be subject to central dispatch. The NESO combines the generators' schedules and adjusts them as necessary to provide the users desired energy transport as well as the system services necessary for the safe and secure running of the power system.

In April 2005, Ofgem implemented British Electricity Trading and Transmission Arrangements (BETTA) by extending NETA into Scotland to establish a Great Britain market. Under this system, parties can enter into bilateral contracts or trade on forward or futures markets on a GB-wide basis. Further information on BETTA can be obtained from the Ofgem website, contact details for which are provided in Section 5.4 of this LTDS.

2.3.6. Embedded Generation

Embedded generating plant connected to our distribution network is diverse in type, capacity, operation, and source energies. We have embedded generation connected across all voltage levels, from large scale onshore wind generation to behind-the-meter domestic solar PV. There are many types of embedded generation, including Combined Heat and Power (CHP) plants, hydro, biomass, biogas, solar PV, wind, and geothermal power. Embedded generation can be stand alone or exist at sites that principally take demand but have significant on-site generation.

A list of embedded generating apparatus connected to the SP Manweb network is given in Appendix 5: Embedded Generation (Table 5).

Our DFES forecasts show that Net Zero will have a significant impact on the generation scenarios applicable for the future years of this LTDS. Although we are in discussions regarding a wide range of renewable generation sites, only those sites which have been secured by a Connection Agreement are considered in this LTDS. Customer commercial confidentiality prohibits third party discussion or release of information for sites that are still undergoing development. Therefore, for the purposes of this LTDS and until site details are otherwise in the public domain, the available renewable generation assumed may be conservative for the period covered by this LTDS.

Generation Connection Considerations

There are many considerations when connecting new generation to the distribution system. Major reinforcements for distribution systems are triggered when forecast power flows exceed the firm transfer capability in an area/network. Power flows are directly related to the magnitude and location of connected generation and demand. If new generation is located in an exporting area (where generation already exceeds demand), power flows will increase and reinforcements could be required. Where reinforcements are required, it can delay the connection of a generator, or reduce its export capability until reinforcements are complete. It is therefore desirable to consider the siting of new generation.

Other considerations such as fault levels, voltage regulation, and the possibility of introducing system instability are also taken into account in the design of a connection. We will consider any connection applications on an individual basis, within the requirements of its licence.

General guidance on the connection of embedded generation together with an indication of site-specific constraints can be found on the DG Connections Information website[18]. The Heat Maps tool described in Section 1.3 can also be used as a resource.

[18] Distributed Generation:
http://www.spenergynetworks.com/pages/distributed_generation.aspx

2.3.7. Distribution System Demand

Our network has to accommodate the peak demands that customers require from its networks. These peak demands often occur for a short period. The forecast trend is for system maximum demand to increase significantly out to 2050.

System Maximum Demand

The maximum system demand for the SP Manweb area for 2023/2024 was 2,639 MW on 18 January 2024 for the half hour period ending 18:30 hours.

Over the five-year period of this LTDS, the winter peak demand for the SP Manweb area is estimated to reach 3,314M W around 2028/2029. The last five year's maximum demand is shown in Table 7 below. The predicted annual maximum demands for the SP Manweb system in the period covered by this LTDS are detailed in Table 8 below.

Table 7: Last five years' peak demands for SP Manweb

Historical System Maximum Demand (MW)				
2019/2020	2020/2021	2021/2022	2022/2023	2023/2024
2,929	2,674	2,690	2,739	2,639

Table 8: Predicted system maximum demand for SP Manweb

Predicted System Maximum Demand (MW)				
2024/2025	2025/2026	2026/2027	2027/2028	2028/2029
2,648	2,786	2,939	3,074	3,207

Looking forward, our DFES forecast a considerable increase in the medium to longer term driven by the electrification of customer heat and transport and increases in industrial and commercial load. These DFES forecasts are undertaken annually for key customer demand and generation metrics up until 2050. We develop these considering a range of sources, including UK and devolved government targets and other industry forecasts. Given the uncertainties out to 2050, we create forecasts for four main energy scenarios. These scenarios represent differing levels of customer ambition, government and policy support, economic growth, and technology development. Our stakeholders review our forecasts and we make changes based on their well-justified feedback – this is a key stage which helps ensure our forecasts reflect the plans and ambitions of the local communities we serve. These forecasts are disaggregated to a local substation level in tables Appendix 3: System Loads (Table 3).

When assessing the demand on the distribution system, due consideration must be given to the impact of embedded generation, CHP schemes, and flexibility services in offsetting demand, all of which will reduce the apparent maximum demand of the local GSP and consequently the distribution system as a whole. The predicted system maximum demand values detailed above reflect such circumstances.

Daily Demand Profile

The daily demand profile varies across the seasons as illustrated in Figure 10. Profiles are displayed for the day of the 2023/2024 Maximum Demand (winter) and the day of the 2023/2024 Minimum Demand (summer).

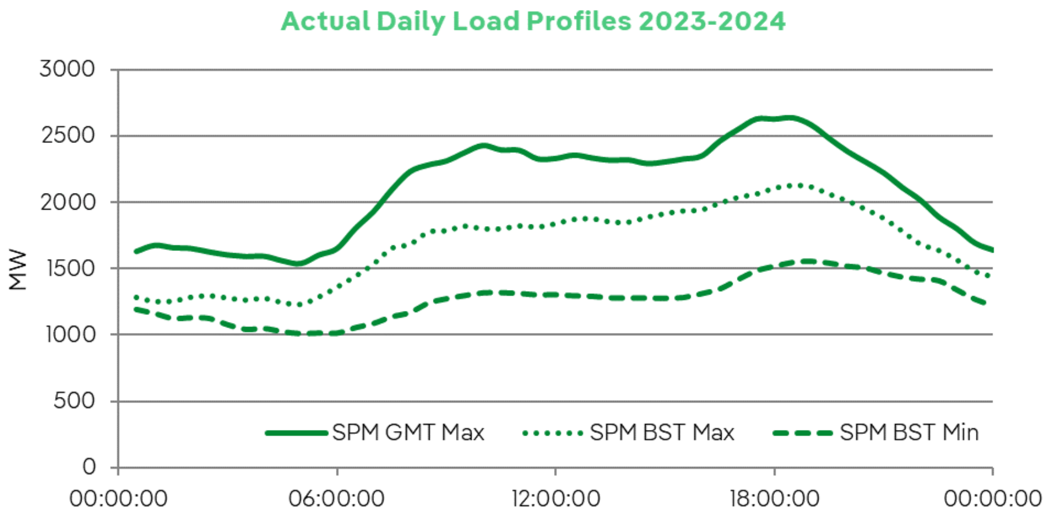

Figure 10: Daily demand profiles

Annual Demand Profile

In addition to the area demand varying throughout the day, it also varies with season. Superimposed on the unvarying demand of continuous process customers, is a wide range of demand profiles of the various customer groups. This results in a profile of area demand that is lowest during mid-summer and gradually increases through autumn to the winter peak. After the system peak, demand reduces gradually as temperatures and daylight hours increase during late winter, into spring and early summer.

The demand profile (based on system HH demand readings) for the past twelve months (1 April 2023 to 31 March 2024) is shown in Figure 11. When carrying out analytical studies to establish load flows, fault levels and system stability, typical load values are utilised to reflect typical system running conditions for winter, spring/autumn and summer. These values have been established at 100%, 80% and 60% of system maximum demand (SMD) respectively.

When considering the annual demand profile, the daily variations of demand obscure the longer-term profile. Therefore, in the interests of clarity, the background data for the annual demand profile shown below have been filtered to improve the legibility of the long-term profile.

The relationship between System Minimum Demand and System Maximum Demand provides a generic system scaling factor which can be used to carry out high-level system studies for light load conditions. For the year 2023/2024, the system minimum load scaling factor for the SP Manweb system is 38.3%.

However, it is important to recognise that the scaling factors for individual substations will vary dependant on the particular load or customer types connected to that substation.

Therefore, while the system scaling factor is representative of the system as a whole, at a local or substation level, the minimum demands may vary significantly from values derived by the application of the system scaling factor.

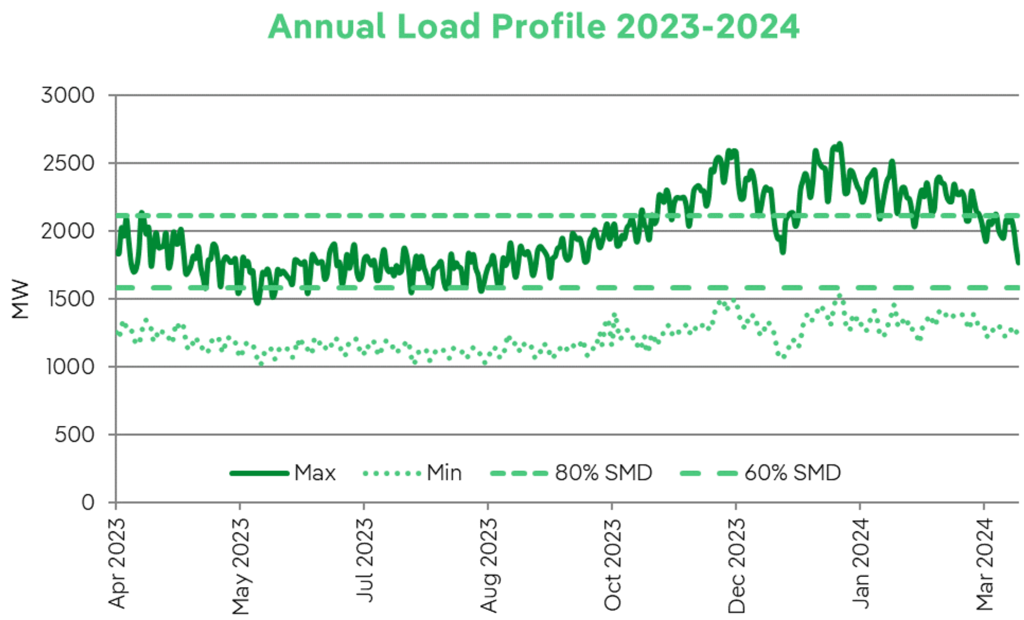

Figure 11: Annual load profile

Load Duration Curve

The system maximum demand will typically occur on a single occasion within the year. The system demand throughout the year is analysed to identify the proportion of the year that each increment of the system demand range occurs. The relationship between proportion of system maximum demand and the percentage of the year is known as the Load Duration Curve. The Load Duration Curve for 2023/2024 is shown below.

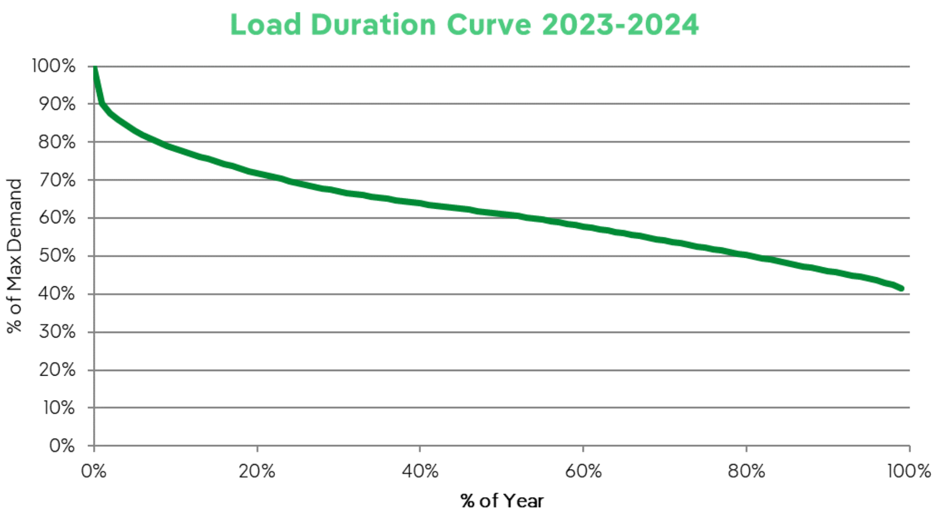

Figure 12: Load duraction curve

2.4. Distribution System Performance

As stated earlier, the Electricity Distribution Licence requires us to publish specific information regarding the capacity and prospective utilisation of its distribution system. The following sections explain the basis on which this information is provided, and the associated tables and figures offer further detail.

2.4.1. Circuit Ratings and Parameters

The continuous thermal rating of a circuit is the maximum power flow that can be passed through the circuit on a continuous basis. This limit is the power that can be transferred without damaging the circuit components and without infringing statutory height clearances on overhead lines (due to thermal expansion and conductor sag), where these, form all or part of the circuit. There may be instances where switchgear or protection system characteristics cause a rating limitation. The thermal rating varies for each season of the year, because of the impact of differing climatic conditions on equipment performance.

Appendix 1: Circuit Data (Table 1) details circuit ratings, circuit resistance, reactance and susceptance.

2.4.2. Transformer Loadings and Parameters

The firm capacity of a substation is calculated as the maximum load it can serve under N-1 contingency conditions. The firm capacity of substations in the SP Manweb area must be calculated from network analysis owing to the interconnected nature of the system. The maximum forecast loading on SP Manweb Primary substation transformers is shown in Appendix 3: System Loads (Table 3). Most BSPs and Primary substations have surplus capacity enabling connection of additional load however where demand exceeds the firm capacity, remedial action may be required to ensure continued compliance with design requirements.

Where the actual maximum demand at a BSP or Primary substation is significantly different from the forecast demand, this may be the result of load being transferred between BSPs for temporary operational conditions and should be confirmed.

Appendix 2: Transformer Data (Table 2) lists transformer impedances and tapping ranges.

2.4.3. Substation Fault Levels

The prospective three-phase fault current for each distribution busbar has been calculated and these values, together with the corresponding X/R ratios, for the year 2023/2024 are detailed in Appendix 4: Fault Levels (Table 4).

The fault levels are calculated under the most onerous network conditions to yield the maximum anticipated fault currents. The most onerous network condition is considered to be when the following conditions occur concurrently:

- All generating apparatus is in service;
- All transformers are set to nominal tap position;
- The system is intact (N); and
- Fault level contributions are included from all independent generators.

The fault levels detailed in Appendix 4: Fault Levels (Table 4) are the Peak Make and RMS Break values with the most onerous conditions assumed. The peak asymmetrical circuit breaker breaking current (Peak Break) can be calculated using the empirical formula quoted in Engineering Recommendation G74. For this purpose, the appropriate system X and R values are also provided in the appendix table.

The actual circuit breaker breaking duty will be less onerous due to the decay of the AC and DC components within the operating time of the protection. Individual circuit breaker duty is further reduced by the value of the fault level contribution from the associated circuits (minimum fault in-feed).

Maximum fault levels must be constrained such that no individual item of switchgear on the system shall be exposed to fault interruption duties greater than its assigned rating. We endeavour to construct and develop the distribution system to ensure that, under the normal operating condition of full interconnection, the fault level will not exceed the equipment rating. However, at certain sites, if the system were to operate fully interconnected, the operation of the system would not meet these criteria.

In established networks, where the calculated fault level is greater than 95% of the equipment design rating, or the network design limit (whichever is lower), a plan is formulated to rectify the issue. The high fault level will be resolved by:

- Replacing equipment that has a fault level rating lower than network design limit,
- Adding additional impedance to circuits,
- Replacing low impedance transformers with higher impedance units,
- Replacing standard two winding transformers for units with two low voltage windings, or
- Establishing entirely new substations.

Planning and implementing a fault level mitigation scheme takes time to complete. In circumstances where the calculated fault level exceeds the equipment design rating, or the network design limit, operational restrictions and interim measures shall be implemented to ensure the safety of staff and the public.

These measures may include:

- Access restrictions to substations,
- Installation of protective screening to create a shield around the equipment,
- De-energisation of equipment to temporarily lower the fault level,
- Auto-switching,
- Circuit re-configuration, and

- Replacement of three-phase termination equipment

The analytical models used for this LTDS have been constructed with the anticipated points of system separation. Actual running arrangements will always maintain the fault level within the plant rating.

As can be seen from the data tables in Appendix 4: Fault Levels (Table 4), the actual fault levels at SP Manweb Primary substations vary considerably. However, in general terms, fault levels on the SP Manweb system can be considered to have design limits for each voltage level. These design limit values are the maximum fault currents anticipated to be encountered in an intact system with normal running arrangements, where circuit outages due to planned or fault outages will increase the system impedance and hence reduce the fault level. The design limit fault levels for 33kV and HV are summarised in Table 9 below.

Table 9: System design maximum fault levels

System Voltage	Three Phase Symmetrical Short Circuit Current		Single Phase Short Circuit Current	
	MVA	kA	MVA	kA
132kV	4,570	20	5,700	25
33kV	1,000[19]	17.5	240	4.2[20]
11kV	250	13.1	250	13.1
6.6kV	150	13.1	150	13.1
6.3kV	143	13.1	143	13.1

Although the maximum design fault level for the 33kV system is given as 17.5 kA, in practice resistance earthing limits the single phase fault level, usually to 4.2kA.

There may be some sites whereby system conditions and operating regimes result in the fault level being higher than the design limit values specified above; in these exceptional circumstances, the equipment specification would take account of actual site conditions. This will also apply to generation sites, where the fault in-feed from the generators added to that of the system may result in the fault levels at the lower voltage being greater than the design limit values. Again, the equipment specification for these sites would take account of the actual site conditions. In general, the fault levels at the higher voltage of these sites will be within the design limits.

[19] Some of the SP Manweb 33kV network is limited to 750 MVA due to legacy switchgear, however this is being migrated to a 1000 MVA planning limit as the system is developed.

[20] The 33 kV system is resistance earthed (via earthing transformers on the transformer 33kV tails and earthing resistors). The single-phase earth-fault current is usually designed to be 1 p.u. on the transformer rating. For example, for SP Manweb network with four units of 60 MVA grid transformers in a BSP group, the design single-phase earth fault current would be 4*60MVA/(sqrt(3)*33kV) = 4.2kA.

HV Fault Levels

The Primary substations in SP Manweb are run in interconnected groups. The fault level in a particular group depends on the number of transformers it contains, the level of interconnection at HV, the operational configuration of the group and the HV system voltage. To enable an assessment of the capabilities of individual source HV busbars, the Primary groups have each been assigned a fault level “band”.

2.4.4. Calculation of Fault Levels

Short circuit currents consist of a DC component with a fast decay rate and an AC component, which has a slower decay rate, relative to the DC component as illustrated in Figure 13 and Figure 14 below.

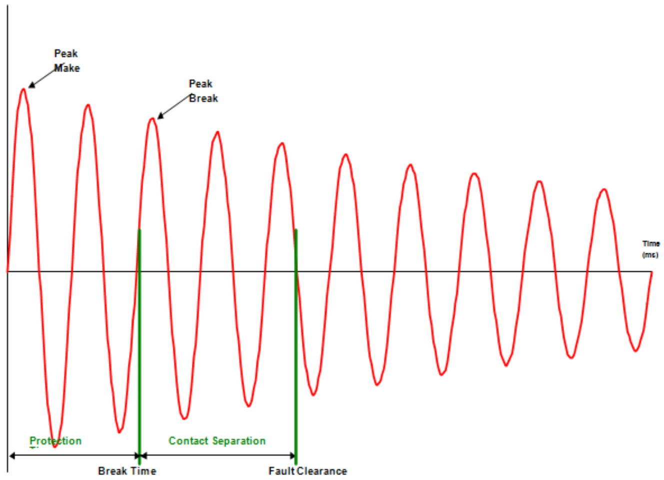

Figure 13: AC component of short circuit current

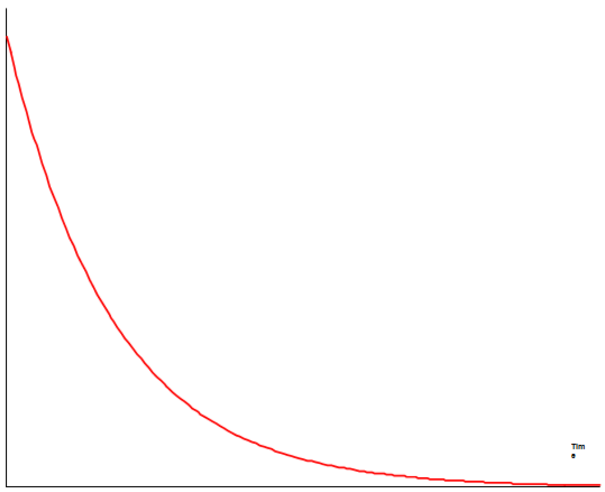

Figure 14: DC component of short circuit current

The magnitude of the DC component depends on the point on the waveform at which the fault occurs. The decay rate of the DC component is exponential, with the rate of decay dependent on the X/R ratio, which represents the ratio of reactance to resistance in the fault current path(s). The magnitude of the fault current contribution from rotating plant to the symmetrical RMS current will also be dependent on the time elapsed from the incidence of the fault.

Circuit breakers are required to have the capability of "making" fault current i.e. closing onto an existing fault and "breaking" fault current i.e. opening and so disconnecting a fault from the system. These duties are defined in terms of Peak Make, RMS Break and Peak Break:

- Peak Make: the maximum possible instantaneous value of the prospective short circuit current and occurs at the first AC peak after fault inception. Due to the time elapsed; there is little decay of the DC component.
- RMS Break: the RMS value of the AC component of the short circuit current at the time the circuit breaker is required to operate and takes no account of the DC component. This is effectively the nominal rating of the equipment.
- Peak Break: the largest instantaneous short circuit current that the circuit breaker may be required to interrupt, taking account of protection operating time. The Peak Break value is an instantaneous value and includes the DC component of the fault current.

Engineering Recommendation G74

An international standard for the manual calculation of system short circuit currents was issued in 1988 as IEC 909 "Short-circuit current calculation in three-phase AC systems". Application of this methodology gave rise to "conservative" results that could possibly lead to over-investment. As a result, a working group developed outline procedures for computer-based methods of calculating short-circuit currents, which could be used as an alternative to the methods presented in IEC 909. The procedure was subsequently issued in 1992 as Engineering Recommendation G74 "Procedure to meet the requirements of IEC 909 for the calculation of short-circuit currents in three-phase AC power systems".

Fault calculations contained within this LTDS have been calculated in accordance with Engineering Recommendation G74. The stated prospective fault current values within the data tables are the Peak Make and RMS Break values with assumed incremental fault in-feeds from rotating apparatus associated with site load, in accordance with the guidelines contained in G74. The Peak Break value will be less than the Peak Make value due to the AC and DC decrement in the protection and breaker operating time. Peak Break values are not included in this LTDS due to the site-specific nature and variability of components and settings.

2.5. Distribution System Capability

To achieve one of the Licence objectives of facilitating competition in the supply of electricity, the distribution system must be capable throughout the year of transferring large power flows between the system entry and system exit points. The transfer capability of the SP Manweb system (i.e. its ability to handle power flows to and from internal and external sources) is discussed here.

The secure transfer capability of the SP Manweb system between any two points can broadly be defined as the maximum load that can be transmitted without a breach of the design criteria (see Section 5.1, references 1 and 6). These criteria, in general, require that no circuit overloads, unacceptable voltage or frequency excursions, or generation instability will be caused by the loss (or withdrawal from service) of any single EHV circuit.

Primary Substation Transformers

Most Primary substations have adequate capacity to accommodate existing and predicted loads. Load monitoring and forward projection permit the identification of locations that require an increase in transformer capacity.

Distribution System Modernisation

We have an ongoing programme of system modernisation. When considering the modernisation needs of the distribution system, the opportunity is taken to rationalise the network configuration such that it satisfies the current needs of the network and its users.

This document also includes details of system modernisation where there are changes to system configuration, apparatus capacity or fault interrupting capability.

2.6. Statutory & Licence Obligations

Under the Electricity Act 1989, as amended by the Utilities Act 2000, an electricity distribution licence holder has a duty to:

- Develop and maintain an efficient, co-ordinated and economical system of electricity distribution; and
- Facilitate competition in the supply and generation of electricity.

A summary of the licence conditions that SP Manweb plc must satisfy, which may be of interest to developers, follows:

i. To prepare and keep in force a Distribution Code which defines the planning and operating procedures which permit the equitable day-to-day management of the Distribution System.

ii. To plan and develop the distribution system in accordance with a Standard not less than that set out in Engineering Recommendation P2 Issue 8 (2023) of the Energy Networks Association Engineering Directorate.

iii. To prepare Statements of Charges for the connection to and use of the distribution system.

iv. If so requested, provide system information, in addition to that contained within this LTDS, indicating present and future circuit capacity, forecast power flows and loading on the distribution system.

v. To restrict the use of information submitted by potential users of the distribution system, which may distort competition.

vi. To comply with the provisions of the Balancing and Settlement Code (BSC).

2.6.1. The Distribution Code

The Distribution Code of Licensed Distribution Network Operators of Great Britain covers all material technical aspects of connections to, operation of and use of the distribution system.

Planning Code

The Planning Code section of the Distribution Code defines the distribution system standards and procedures to be used in the connection application process between a potential user of the system and us. The document defines the planning criteria adopted by us, the technical data requirements to be supplied by the user, and the mandatory response times for us to make a contractual offer.

Connection Conditions

The Connection Conditions section of the Distribution Code specifies technical and operational criteria to be complied with by all users of the SP Manweb system and sets out the procedures by which we shall ensure compliance by users with the above criteria.

2.6.2. Distribution Charging Statements

There are charges applied to any user for:

- Connection to the distribution system; and
- Use of the distribution system.

The charges for a user to connect to the SP Manweb system are defined in the document entitled "Statement of Methodology and Charges for Connection to SP Distribution plc and SP Manweb plc's Electricity Distribution Systems". The annex to this document defines the difference between contestable and non-contestable work relating to a connection and the arrangements which apply where a user opts to appoint an approved contractor to carry out contestable work.

The charges paid by users authorised to make use of the SP Manweb distribution system are defined in the document entitled "SP Manweb plc – Use of System Charging Statement".

These statements are prepared in accordance with Condition 13 and 14 of our Electricity Distribution Licence and detail the principles upon which charges for the use of, and connection to, the SP Manweb system will be based.

The charges are designed to provide a transparent pricing framework within which particular charges reflect and recover the costs necessarily incurred by SP Manweb in providing particular services. The Licence requires that the terms and charges contained in these statements be reviewed at least once each year.

Use of System charges relate to those parts of the distribution system which facilitate the bulk transfer of electricity between Entry Points (where electricity is collected from transmission or generators) and Exit Points or bulk supply circuits (where electricity is delivered to individual premises).

Connection charges relate to assets which are dedicated to the provision of connections between the distribution system and either generators (Entry assets) or private networks (Exit assets).

These statements can be obtained from the SP Energy Networks website[21].

2.7. Advice for Developers

This document highlights many of the technical elements that need to be considered when connecting to the distribution network. The reference documents listed in Sections 5.1 and 5.2 will assist developers to assess the various technical and physical aspects of a connection. These cannot however provide the same benefits as discussion of specific requirements and connection arrangements with us at the earliest opportunity and this course of action is highly recommended.

The detailed system information provided as part of this LTDS is for general guidance and will prove of use to developers in identifying opportunities and assessing the relative merits of competing sites. However, as the existing and future distribution system is continuously evolving in response to operational requirements, system developments and customer applications, the data provided within this LTDS may be subject to revision. Such amendments may have an impact on the detailed planning of a site-specific development. Again, we therefore recommend that developers contact us at an early stage when planning the development of a specific site. We will be pleased to discuss developers' plans, provide technical information and advice on connection, technical or financial issues. These discussions will be confidential until such times as the connection is finalised by the conclusion of a Connection Agreement.

Where additional system infrastructure is required to cater for large volumes of generation, a clear need case must be demonstrated. Potential generation developers are encouraged to contact SP Energy Networks at the earliest opportunity to register interest.

Customers, developers, or installers wishing to install embedded generating units have a legal requirement to contact us prior to installation or commissioning (the only exception is one-off G99 generators i.e. less than 16 A per phase).

We require advanced notification for multiple applications of small units, or single installations of larger units, in order to assess their impact on the supply system and other users. Applicants will be advised of any works, costs and timescales which arise as a consequence of their proposed installation. Details of the process are available on the SP Energy Networks website[22].

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[21] Connections Use of System and Metering Services: https://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.aspx

[22] Connection Application Guide: http://www.spenergynetworks.co.uk/pages/distributed_generation.asp

Applications for connection to our distribution network should be addressed to Customer Connections, contact details for whom are included in Section 5.4.

2.7.1. Offer of Terms for Connection

The Electricity Distribution Licence conditions specify the timescale(s) within which we must provide a formal "Offer of Terms for Connection" in response to a formal "Application for Connection from a Customer". The Offer will specify any extension to the distribution network necessitated by the applicant's development. It will also detail both capital related payments together with any specific conditions relating to that site.

2.7.2. Project Timescales

In general, the timescale of any distribution system modifications or additions is dependent on the extent of the work and the plant requirements of the project. We will always endeavour to accommodate customer timescales and requirements within the constraints of system outages and equipment procurement. Discussions during the early planning phase will facilitate mutual agreement on project timescales that are achievable and meet customer requirements.

2.7.3. Interest in Connection to the SP Manweb System

Certain types of development often congregate in the same area, which means some areas of the distribution system are more prone to interest than others. Appendix 5: Embedded Generation (Table 5) and Appendix 6: Connection Activity (Table 6) detail the level of interest in connection in all areas of the SP Manweb distribution system for both generation and demand developments.

3. Part 3: Detailed Information

This part of the Long Term Development Statement comprises the following sections:

- Circuit Data (Section 3.1)
- Transformer Data (Section 3.2)
- System Loads (Section 3.3)
- Fault Levels (Section 3.43.4)
- Embedded Generation (Section 3.5)
- Connection Activity (Section 3.6)
- Substation Abbreviation Codes (Section 3.7)
- Predicted Changes (Section 3.8)
- System Schematics (Section 3.9)
- Geographic Plans (Section 3.10)

A brief description of the information provided within each category is given in the following sections, while the detailed information tables for each of these sections can be found in separate Appendix documents.

3.1. Table 1: Circuit Data

The data included in this table is derived from power system analysis software, and therefore the circuit parameters detailed in the tables are based on the equipment between analytical node points. As some circuits may have intermediate node points, or a number of components, this aspect should be taken into consideration when assessing overall (end-to-end) circuit parameters. Those circuit sections labelled S/C, or short circuit, represent circuit breakers, switches, or busbar connections of effectively zero impedance.

The Circuit Data table can be found in Appendix 1: Circuit Data (Table 1).

3.2. Table 2: Transformer Data

This table provides the parameters for each group of transformers on the SP Manweb system.

The Transformer Data table can be found in Appendix 2: Transformer Data (Table 2).

3.3. Table 3: System Loads

Future levels of demand are based on the best estimate from information presently available. The minimum area demand on the SP Manweb system, as a percentage of the system maximum demand value, is detailed in Section 2.3.7. The annual system demand profile can be considered representative of the annual demand profile at the majority of Primary substations.

Generation is connected to a number of Primary substations and BSPs. This has the effect of supporting/offsetting local demand. Therefore, the stated maximum demands for these locations may be lower than the connected load, if these generators were operating at the time of the maximum demand. Similarly, significant generation in the form of CHP schemes can be embedded within customers' installations, which can have the effect of reducing the demand at their supply point and consequently the demand of the corresponding Primary substation or BSP.

The System Demand table can be found in Appendix 3: System Loads (Table 3).

3.4. Table 4: Fault Levels

This table provides plant fault levels for the distribution system as at the data freeze date. A small number of authorised proposals that will be completed after the data freeze date and that will potentially have a significant impact on fault levels have also been included in order to provide the most appropriate system data that is currently available. These can be found in Part 4: Development Proposals. For ease of reference, the table is displayed by voltage level and includes 132kV and 33kV. An additional section is provided on the fault level banding of 11kV busbars, where the fault level at any one location on the 11kV network is variable owing to the heavily interconnected nature of the SP Manweb system.

Short circuit currents are expressed in kA and have been calculated for three phase faults under maximum plant conditions. The tables provide details of the Peak Make and RMS Break duty. The three phase equipment rating (expressed in kA) refers to the RMS Break value. Switchgear ratings are also provided for each substation.

The fault level values provided in the appendix tables include a value for the assumed fault in-feed values from rotating apparatus associated with site load, in accordance with the guidelines contained in Engineering Recommendation G74. Although the load associated fault currents are included in the values, as an indication of the G74 magnitude, the G74 Peak Make component value is displayed. While in some cases apparatus capability may be in excess of the design limit, as described in Section 2.4.3, system fault levels will always be constrained within the relevant design limit.

Short circuit currents at customer locations are based on the assumed system configuration detailed in Appendix 9: System Schematics (Table 9).

The Fault Level table can be found in Appendix 4: Fault Levels (Table 4).

3.5. Table 5: Embedded Generation

Details of generation embedded within the distribution system are provided, together with an indication of the source GSP substation.

The Generation table can be found in Appendix 5: Embedded Generation (Table 5).

3.6. Table 6: Connection Activity

Details of connection applications and budget estimate offers made are provided, together with an indication of the source GSP substation.

The Connection Activity table can be found in Appendix 6: Connection Activity (Table 6).

3.7. Table 7: Substation Abbreviation Codes

In order to accurately identify equipment and locations for system analysis, network studies and network administration, a standardised method of plant referencing has been adopted.

Each substation is assigned a unique four-character abbreviation code which is derived from the site name. This then permits plant and circuits to be identified by referring them to substation codes. A unique node reference is obtained by appending two additional characters to the four-character substation code. The additional characters are generated to ensure that the node is uniquely identified and can comprise letters, alphabetic characters or a dash. By adopting this convention, all sites and equipment can be uniquely identified. Any circuit or item of equipment simply connects two node points.

The Substation Abbreviation Codes can be found in Appendix 7: Substation Abbreviation Codes (Table 7).

3.8. Table 8: Predicted Changes

Appendix 8: Predicted Changes (Table 8) outlines the development opportunities for the SP Manweb network, highlighting connection opportunities for generation and load.

3.9. Table 9: System Schematics

Figures providing 132kV and 33kV connectivity are provided in Appendix 9: System Schematics (Table 9).

3.10. Table 10: Geographic Plans

Geographic plans of the SP Manweb network area are provided in Appendix 10: Geographic Plans (Table 10).

3.11. Requests for Additional Information

The level of information provided within this LTDS is considered suitable to present users with an understanding of the overall system, together with sufficient detailed information to facilitate the assessment of potential developments. We welcome early engagement with developers to collaboratively develop their project and the subsequent connection works in a coordinated, economic, and efficient manner.

In the event that additional information or clarification is required for finite areas of the network, contact should be made to the relevant points of contact as detailed in Section 5.4 of this document.

Where the data request requirements are relatively localised and readily accessible, the data will be provided as soon as reasonably practicable. Depending on resource requirements and availability, this could be achieved within a few working days. Where this will take longer, we will provide an estimate of the timescales for provision of the data.

However, where the data requirement request requires significant research or analysis, we will advise on the estimated cost of this work and seek agreement prior to commencement.

4. Part 4: Development Proposals

This part of the Long Term Development Statement comprises two sections:

- Changes to the Distribution System
- Application & Connection Activity

4.1. Changes to the Distribution System

While all reasonable care has been taken in the preparation of this data, SP Manweb Plc is not responsible for any loss that may be attributed to the use of this information.

Brief descriptions of future **AUTHORISED** changes to the system are given in Appendix 8: Predicted Changes (Table 8). Major developments which will impact the configuration of the Distribution System are included. It should be noted that projects may be subject to significant amendment or cancellation.

As the distribution system is constantly undergoing change in response to system and customer requirements, it should also be noted that circuits, substations, or other equipment which are indicated as existing or planned within this LTDS, may be excluded from future LTDSs due to developments which are unforeseen at present, or be subject to significant amendment.

4.2. Application & Connection Activity

An indication of application and connection activity, for both generation and demand, is provided in Appendix 8: Predicted Changes (Table 8). The data is analysed by connection points to the network in terms of Grid Supply Points and (where applicable) Primary substations.

As previously described, there is a confidentiality obligation requiring us to respect client confidentiality such that the release of any information shall not distort competition. In order to meet this requirement, information relating to the connection of commercial developments will not be published until such times as these developments become authorised by the conclusion of a Connection Agreement. Therefore, any such developments are excluded from the tables provided.

5. Part 5: Additional Information

5.1. Technical References

1. **Distribution Code of Licensed Distribution Network Operators of Great Britain.** The Code covers technical parameters and considerations relating to the use of and connection to public distribution systems. Information about the distribution code can be obtained on the distribution code website[23]. Code Annex documents are free to download from the distribution code website.

2. **Electricity Act 1989.** This legislation sets out the regulatory framework and licensing regime for the UK Electricity Supply Industry.

3. **Electricity Safety, Quality and Continuity Regulation 2002.** The purpose of these regulations is to secure the safety of the public and ensure a proper and efficient supply of electrical energy. The Electricity Safety, Quality and Continuity Regulation 2002 supersede the Electricity Supply Regulations 1988. Copies of the regulations can be obtained from HMSO[24].

4. **GB Grid Code**. The Code covers all technical aspects relating to the planning, operation and use of the interconnected transmission system and the operation of electrical apparatus connected to that system. It is a requirement of the Electricity Distribution Licence that the SP Manweb system complies with the provisions of the GB Grid Code. This document is available on the National Grid website[25].

5. **Utilities Act 2000.** This legislation sets out a series of reforms for the system of regulation of the utility industries. The act established a single Gas and Electricity Markets Authority (the Authority) in place of the twin posts of Director-General of Electricity Supply and Director-General of Gas Supply.

6. **Engineering Recommendation (EREC) P2 Issue 8, "Security of Supply".** P2 Issue 8 sets out the minimum standard to be applied in the planning of the distribution system.

7. **Engineering Recommendation (EREC) G74,** "Procedure to Meet the Requirements of IEC 909 for the Calculation of Short-Circuit Currents in Three-Phase Power Systems". Issued by the Electricity Association in 1992. Supported by Electricity Association Engineering Technical Report No. 120, "Application Guide to Engineering Recommendation G74.

8. **Engineering Recommendation (EREC) G5 Issue 5**, "Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Equipment to Transmission and Distribution Systems in the United Kingdom".

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[23] Distribution Code website: www.dcode.org.uk
[24] HMSO: www.hmso.gov.uk/si/si2002/20022665.htm
[25] NESO website: https://www.neso.energy/industry-information/codes/grid-code-gc

9. **Engineering Recommendation (EREC) P28 Issue 2**, “Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution systems in the United Kingdom”.
10. **Engineering Recommendation (EREC) P29**, “Planning Limits for Voltage Unbalance in the United Kingdom”.
11. **Engineering Recommendation (EREC) G99 Issue 1**, “Requirements for the connection of generating equipment in parallel with public distribution networks on or after 27 April 2019”.
12. *Reference intentionally left blank.*
13. **Engineering Recommendation (EREC) P16**, EHV or HV Supplies to Induction Furnaces (Supported by ACE Report No 48).
14. **Engineering Recommendation (EREC) P18**, Complexity of 132 kV circuits.
15. **Engineering Recommendation (EREC) G98 Issue 1**, “Requirements for the connection of Fully Type Tested Micro-generators (up to and including 16 A per phase) in parallel with public Low Voltage Distribution Networks on or after 27 April 2019”.
16. **Engineering Recommendation (EREC) G78 Issue 4**, Recommendations for low voltage connections to mobile telephone base stations with antennae on high voltage structures.
17. **Engineering Recommendation (EREC) G81**, Framework for design and planning, materials specification and installation and record for Greenfield low voltage housing estate installations and associated, new, HV/LV distribution substations.
18. **Engineering Recommendation (EREC) G12 Issue 4**, Requirements for the application of protective multiple earthing to low voltage networks.
19. **Engineering Recommendation (EREC) P17**, Current Rating Guide for Distribution Cables.
20. **Engineering Recommendation (EREC) P24**, AC traction supplies to British Rail.
21. **Engineering Recommendation (EREC) P25 Issue 2**, The short-circuit characteristics of single-phase and three-phase low voltage distribution networks.
22. **Engineering Recommendation (EREC) P27**, Current Rating Guide for High Voltage Overhead Lines Operating in the UK Distribution System.
23. **Engineering Technical Report (ETR) 122**, Guide to the application of Engineering Recommendation G5/4 in the assessment of harmonic voltage distortion and connection of non-linear equipment to the electricity supply system in the U.K.
24. **Engineering Technical Report (ETR) 124**, Guidelines for Activity Managing Power Flows Associated with the Connection of a Single Distributed Generation Plant.
25. **Engineering Technical Report (ETR) 126**, Guidelines for Activity Managing Voltage Levels Associated with the Connection of a Single Distributed Generation Plant.
26. **Engineering Report (EREP) 130,** Application guide for assessing the capacity of networks containing distributed generation.

5.2. SP Manweb Documentation

27. **ESDD-02-012**: Framework for design and planning of low voltage housing developments, including underground networks and associated, new, HV/LV distribution substations. This document details the SP Distribution plc and SP Manweb plc requirements for the design of low voltage underground cable electricity networks including their new associated HV/LV distribution substations on greenfield housing developments.

28. **EPS-03-027**: Materials Specification Framework for Greenfield Low Voltage Housing Estate Underground Network Installations and Associated, new, HV/LV Distribution Substations. This document details materials requirements for Low Voltage underground cable electricity networks including new associated HV/LV distribution substations on greenfield housing developments.

29. **EPS-02-005**: Installation and Record Framework for Greenfield Low Voltage Housing Developments, Underground Networks and Associated, New, HV/LV Distribution Substations. This document details installation requirements for Low Voltage underground cable electricity networks including new associated HV/LV distribution substations on greenfield housing developments.

30. **EPS-03-031**: Materials Specification Framework for Industrial and Commercial Underground Connected Loads Up to and including 11 kV. This document details materials requirements for underground cable electricity networks up to and including 11 kV for connections to Industrial and Commercial Customers.

31. **EPS-02-006**: Installation and Record Framework for Industrial and Commercial Underground Connected Loads Up to and Including 11 kV. This document details installation requirements for underground cable electricity networks up to and including 11 kV for connections to Industrial and Commercial Customers.

Details on how to obtain copies of the Engineering Recommendations and Engineering Technical Reports is available from the ENA website[26]. Licence documentation is available from the Office of Gas and Electricity Markets (Ofgem) website[27].

SP Manweb documentation is available from the library section of the SP Energy Networks (SPEN) website[28].

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[26] ENA website: http://www.energynetworks.org/
[27] Ofgem website: https://www.ofgem.gov.uk
[28] SP Energy Networks document library: https://www.spenergynetworks.co.uk/pages/documents.aspx

5.3. SPEN Relevant Documentation

Distribution Long Term Development Statement (SP Manweb)

This document is available free of charge via internet download (registration required) as described in Section 1.6.

Where additional information, or clarification, is required for finite areas of the network, contact should be made to the relevant points of contact detailed in Section 5.4.

SP Manweb LC14 Charging Statement – April 2024

This statement details the Distribution Use of System charges that SP Manweb applies. The statement is available free of charge via internet download[29].

Statement of Methodology and Charges for Connection to SP Distribution Plc and SP Manweb Plc's Electricity Distribution Systems

This statement details the basis for charging for the use of the distribution system and is available free of charge via internet download[30].

Distribution Code of Licensed Distribution Network Operators of Great Britain

The Distribution Code contains planning and operational procedures to permit the equitable day-to-day management of the SP Manweb system. This document is available from the Distribution Code website[31].

Electricity Ten Year Statement

The E-TYS provides details of the performance of the GB Transmission system for the previous year. This document is available free of charge via internet download from the NESO website[32].

GB Grid Code

The Grid Code contains planning and operational procedures to permit the equitable day-to-day management of the GB Transmission system. This document is available free of charge via internet download from the NESO website[33].

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[29] Statement of Charges for Use: http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp

[30] Statement of Charges for Use: http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp

[31] Distribution Code download: http://www.dcode.org.uk/

[32] ETYS download: https://www.neso.energy/publications/electricity-ten-year-statement-etys

[33] GB Grid Code download: https://www.neso.energy/industry-information/codes/grid-code-gc

5.4. Useful Contacts

Should any customer wish to discuss an existing connection or proposed development, they should contact the Network Connections team in the first instance. Dependent on the nature and size of the development, the enquiry will then be routed to the appropriate group.

Similarly, if a user requires some additional system data to facilitate their assessment of a development, they should also contact Network Connections team.

Network Connections (SP Manweb)	SP Energy Networks Network Connections PO Box 290 Lister Drive Liverpool L13 7HJ L13 7HJ ☎ 0845 270 0783

Dependent on the nature and size of the development, the enquiry will then be routed to the appropriate group.

Points of contact for documentation are as referenced throughout this LTDS.

SPEN CEO	Ms N. Connelly Managing Director SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 1950
SPEN COO	Mr G. Jefferson Chief Operating Officer SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G2 5AD ☎ 0141 614 1898
SP Manweb Director	Mr L. O'Sullivan SP Manweb Director SP Energy Networks 3 Prenton Way Birkenhead Prenton CH43 3ET ☎ 0141 614 5425
Network Planning and Regulation Director	Mr S. Mathieson Network Planning and Regulation SP Energy Networks ScottishPower House 320 St. Vincent Street Glasgow G5 2AD ☎ 0141 614 1612

OFGEM (London)	Office of Gas and Electricity Markets 10 South Colonnade Canary Wharf London E14 4PU ☎ 020 7901 7000 https://www.ofgem.gov.uk/
Energy Networks Association	Energy Networks Association 4 More London Riverside London SE1 2AU ☎ 020 7706 5100 http://www.energynetworks.org/
National Energy System Operator	NESO Faraday House Warwick Technology Park Gallows Hill Warwick CV34 6DA ☎ 019 2665 3000 https://www.neso.energy/
National Grid Electricity Distribution	National Grid Electricity Distribution Toll End Road Tipton DY4 0HH ☎ 0800 096 3080 / 0121 623 9007 https://www.nationalgrid.com/electricity-distribution
Electricity North West	Electricity North West 304 Bridgewater Place Birchwood Park Warrington WA3 6XG ☎ 0800 195 4141 https://www.enwl.co.uk/